0000126067

Application
E-01345A-11-0224

PART 2 OF 3
BAR CODE # 0000126067

To review remaining parts please see the following:

PART 1 OF 3 BAR CODED #0000126066

PART 3 OF 3 BAR CODED #0000126068

Rate Schedule

ARIZONA PUBLIC SERVICE COMPANY

Index to Rate Schedules

CLASSIFICATION OF SERVICES

RESIDENTIAL

	E-12	Standard Rate
FROZEN*	ET-1	Time-of-Use – Time Advantage Rate
	ET-2	Time-of-Use – Time Advantage 7PM-NOON
FROZEN*	ECT-1R	Time-of-Use with Demand Charge – Combined Advantage Rate
	ECT-2	Time-of-Use with Demand Charge – Combined Advantage 7PM-NOON
	ET-SP	Time-of-Use – Time Advantage Super Peak 7PM-NOON
	Low Income	
	E-12 Low Income	Standard Rate
FROZEN*	ET-1 Low Income	Time-of-Use – Time Advantage Rate
	ET-2 Low Income	Time-of-Use – Time Advantage 7PM-NOON
FROZEN*	ECT-1R Low Income	Time-of-Use with Demand Charge – Combined Advantage Rate
	ECT-2 Low Income	Time-of-Use with Demand Charge – Combined Advantage 7PM-NOON
	Riders	
	E-3	Energy Support Program
	E-4	Medical Care Equipment Support Programs
	CPP-RES	Critical Peak Pricing - Residential
NEW	PTR-RES	Peak Time Rebate - Residential

GENERAL SERVICE

	E-30	Extra Small Unmetered
	E-32 XS	Extra Small General Service (0kW – 20 kW)
	E-32 S	Small General Service (21kW – 100 kW)
	E-32 M	Medium General Service (101kW – 400 kW)
	E-32 L	Large General Service (401kW +)
	E-32TOU XS	Time-of-Use – Extra Small General Service (0kW – 20 kW)
	E-32TOU S	Time-of-Use – Small General Service (21kW – 100 kW)
	E-32TOU M	Time-of-Use – Medium General Service (101kW – 400 kW)
	E-32TOU L	Time-of-Use – Large General Service (401kW +)
	E-34	Extra Large General Service
	E-35	Extra Large General Service Time-Of-Use
	Riders	
CANCEL	E-53	Athletic Stadiums & Sports Fields
	E-54	Seasonal Service
	CPP-GS	Critical Peak Pricing – General Service
NEW	IRR-GS	Interruptible Rider – Extra Large General Service
	PPR	Preference Power
NEW	AG-1	Alternative Generation Rate

ARIZONA PUBLIC SERVICE COMPANY

Index to Rate Schedules

CLASSIFIED

FROZEN*	E-20	Time-of-Use for Religious Houses of Worship
NEW	E-36 M	Station Use Service M
	E-36 XL	Station Use Service XL
CANCEL	E-40	Agricultural Wind Machine Service
	E-47	Dusk to Dawn Lighting Service
	E-56	Partial Requirements Service
	E-58	Street Lighting Service
	E-59	Government Owned Street Lighting Systems
	E-67	Municipal Lighting Service - City of Phoenix
CANCEL	E-114	Share the Light – Lower Miami & Claypool – FROZEN
CANCEL	E-116	Share the Light – Central Heights & Country Club Manor – FROZEN
CANCEL	E-145	Share the Light – Ajo Heights – FROZEN
	E-221	Water Pumping Service
	E-221-8T	Water Pumping Service Time-of-Use
CANCEL	E-249	Share the Light – Camp Verde – FROZEN
	GS-SCHOOLS M	Time-of-Use - Elementary and Secondary Schools (0kW – 400 kW)
	GS-SCHOOLS L	Time-of-Use - Elementary and Secondary Schools (401kW +)
	Riders	
UNCHANGED	EPR-2	Purchase Rates for Qualified Facilities 100 kW or Less for Partial Requirements
	EPR-6	Net Metering Pilot Program
	GPS-1	Green Power Block Schedule
	GPS-2	Green Power Percent Schedule
	GPS-3	Green Power Block Schedule for Special Events
	E-56 R	Partial Requirements Standard Contract
CANCEL	SOLAR-2	Individual Solar Electric Service
CANCEL	SOLAR-3	Solar Power Pilot Program
UNCHANGED	CMPW-01	Community Power – Flagstaff SANDVIG 04
UNCHANGED	RSSP	Rural Schools Solar Program

ARIZONA PUBLIC SERVICE COMPANY

Index to Rate Schedules

ADJUSTMENTS

	DSMAC-1	Demand Side Management Adjustment Charge
	REAC-1	Renewable Energy Standard
UNCHANGED	SDR	Self Directed Renewable Resources
	PSA-1	Power Supply Adjustment
UNCHANGED	RCDAC-1	Returning Customer Direct Access Charge
	TCA-1	Transmission Cost Adjustment
CANCEL	EIS	Environmental Improvement Surcharge
NEW	ERA-1	Environmental and Reliability Account
NEW	EIA-1	Efficiency and Infrastructure Account

Notes:

(1) Redline and final rate schedules have been provided for all rates, expect that redline rate schedules have not been provided for new rates or for rates that are unchanged in this rate case.

(2) Schedules marked FROZEN* were frozen to new customers at times noted on the individual schedule per Arizona Corporation Decision 71448.

(3) Unless otherwise noted, elements of rate schedule have been changed.

Classification of Service

A. RESIDENTIAL SERVICE

1. Residence - Single

Residential service to a single residence covers electric service to a private residence or individually metered apartment unit, only.

Outbuildings on the same premises, such as a garage, a workshop or a guest house, may be connected to the residential service meter, but only if such outbuildings form a part of the main dwelling unit and the outbuilding's primary use is not for business puposes or as rental property. "Dwelling unit" means a structure or the part of a structure that is used as a home, residence or sleeping place by one person who maintains a household or by two or more persons who maintain a common household.

2. Residence - Multiple

Residential service to two or more residences on the same premises or a residence or residences subdivided into two or more individual housekeeping apartments shall not be supplied through one meter on a Residential Service Rate Schedule.

Individual meters will be installed by the Company for each individual dwelling or housekeeping unit. If, for any reason, a separate meter is not installed for each individual dwelling or housekeeping unit, then the appropriate General Service Rate Schedule will be used for billing for the service supplied through the single meter.

3. Professional Offices or Commercial Activities in Dwellings

The supply of service under a Residential Rate Schedule to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the energy used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters.

Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electric equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises shall be classified as non-residential and the appropriate General Service Rate Schedule shall be applied. Customer may at his option provide separate circuits so that the residential uses can be metered and billed separately under the appropriate Residential Service Rate Schedule, and the other uses under the appropriate General Service Rate Schedule.

4. Farm and Rural Residences

The Residential Service Rate Schedules are available for electric service through one meter to a farm residence, and the usual farm uses outside the dwelling unit, but not if the use extends to operations such as canning plants, packing plants, stone quarries, ice cream manufacturing plants, stores, restaurants, tea rooms, tourist and trailer camps, gasoline stations, automobile service stations, repair shops, blacksmith shops or any other commercial or non-farming operation.

In no case shall the use extend to the processing, preparing or distributing of products not raised on the same farm and in no cases shall the use extend to a hatchery, dairy, butchery, greenhouse, or any other specialized operation unless such operation is conducted solely by the farmer and is incidental to the usual farm residence uses.

A. RESIDENTIAL SERVICE (cont)

Customer may at his option elect to take the entire service under the appropriate General Service Rate Schedule, or may provide separate circuits so that the residential uses, together with the usual farm uses outside the dwelling unit, can be metered and billed separately under the appropriate Residential Service Rate Schedule, and the other uses under the appropriate General Service Rate Schedule.

The Residential Service Rate Schedules are not available for any use outside the dwelling unit on a farm which is not operated by an individual owner or lessee, occupying the farm residence.

B. GENERAL SERVICE

This covers service to any establishment for any purpose not prohibited by the rate schedule or Agreement for Service.

The General Service Rate Schedules are available only when all electric service required on the premises is taken through one meter at one point of delivery, except that:

(a) General Service Rate Schedules are available for more than one point of delivery on any one premise, provided that in such event, service supplied at each point of delivery will be separately metered and separately billed.

(b) The General Service Rate Schedules will be available for service to that portion of the Customer's premises which cannot be served at the Residential Service Rate Schedule or a Classified Service Rate Schedule. Service to such portion of the premises shall be considered as service to a separate customer, and all electric service taken therein at the General Service Rate Schedule must be through one meter at one point of delivery.

C. CLASSIFIED SERVICE

Classified service covers service for which specific rate schedules are available, due to the nature and load characteristics of the particular business. For such service, the General Service Rate Schedule may be used, except as specifically prohibited in that schedule, while Classified Rate Schedules are available only to those businesses complying with the specific requirements of the particular schedule.

Service supplied under a Classified Rate Schedule shall be used only for the purposes specified in such rate schedule. In the event the Company questions whether the service is being used in compliance with said rate schedule, the customer shall have the burden of establishing such compliance to the satisfaction of the Company. In the absence of such compliance, the Company may substitute an appropriate General Service Rate Schedule.

A customer conducting mixed operations, a part of which may be served at a Classified Rate Schedule may, at his option, elect to take the entire service under the General Service Rate Schedule or may provide separate circuits so that the classified service can be metered and billed separately at the available classified schedule, and the other uses metered and billed under the available General Service Rate Schedule.

C. CLASSIFIED SERVICE (cont)

The Classified Services, for which specific rate schedules are available, excluding special street light service, are listed below.

Schedule No.	Classification
E-20***	Time of Use for Religious Houses of Worship
E-36M	Station Use Service M
E-36 XL	Station Use Service L
E-40*	Agricultural Wind Machine Service
E-47**	Dusk to Dawn Lighting Service
E-56	Partial Requirements Service for On-Site Generation Facilities over 100 kW
E-58**	Street Lighting Service
E-59	Government Owned Street Lighting Systems
E-221	Water Pumping Service
E-221-8T	Water Pumping Service Time of Use
E-56 R	Partial Requirement Standard Contract –for Generation Equipment over 100 kW
Solar-2*	Individual Solar Electric Service
Solar-3	Solar Power Pilot Program
EPR-2	Purchase Rates for Qualified Facilities under 100 kW for Partial Requirements
EPR-6	Net Metering
PPR	Preference Power Rider
CMPW	Community Power Project – Flagstaff Pilot Rate
GS-Schools M	Time of Use – Elementary and Secondary Schools (0 kW – 400 kW)
GS- Schools L	Time of Use – Elementary and Secondary Schools (400 kW +)
RSSP	Rural Schools Program (Rider Rate)

* Frozen Rate.
** Partially Frozen Rate.
*** Frozen Rate as of Dec 31, 2010.

Residential

RATE SCHEDULE E-12
RESIDENTIAL SERVICE
STANDARD RATE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes. Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplemental or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services), and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $ 0.390 per day

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.09110 per kWh for the first 400 kWh, plus $0.13180 per kWh for the next 400 kWh, plus $0.15723 per kWh for the next 2200 kWh, plus $0.16800 per kWh for all additional kWh	$0.08836 per kWh

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge: $ 0.188 per day

RATES (cont)

Unbundled Components (cont)

Revenue Cycle Service Charges:

Metering	$ 0.112	per day
Meter Reading	$ 0.038	per day
Billing	$ 0.052	per day
System Benefits Charge:	$ 0.00165	per kWh
Delivery Charge:	$0.03712	per kWh

Generation Charges:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.05233per kWh for the first 400 kWh, plus $0.09303 per kWh for the next 400 kWh, plus $0.11846 per kWh for the next 2200 kWh, plus $0.12923per kWh for all additional kWh	$0.04959 per kWh

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448, and XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXXX.

ADJUSTMENTS (cont)

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE ET-1
RESIDENTIAL SERVICE TIME-OF-USE
TIME ADVANTAGE RATE

FROZEN

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatthour meter.

Additionally, this rate schedule is applicable only to those customers being served on the Company's Rate Schedule ET-1 prior to January 1, 2010.

This schedule is not applicable to breakdown, standby, supplemental or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services, and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates, plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $ 0.579 per day

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 0.16488 per kWh during On-Peak hours, plus $ 0.06601 per kWh during Off-Peak hours	$0.12508 per kWh during On-Peak hours, plus $0.06258 per kWh during Off-Peak hours

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge: $ 0.260 per day

RATES (cont)

Unbundled Components (cont)

Revenue Cycle Service Charges:

Metering	$ 0.204	per day
Meter Reading	$ 0.038	per day
Billing	$ 0.0770	per day
System Benefits Charge:	$ 0.00165	per kWh
Delivery Charge:	$ 0.02930	per kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.13393 per kWh during On-Peak hours, plus $0.03506 per kWh during Off-Peak hours	$0.09413 per kWh during On-Peak hours, plus $0.03163 per kWh during Off-Peak hours

FROZEN

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

TIME PERIODS

The standard Company On-Peak time period for residential rate schedules is 9 a.m. to 9 p.m. Monday through Friday. All hours not included in the On-Peak time period shall be Off-Peak hours.

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

FROZEN

ADJUSTMENTS (cont)

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. XXXX.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. XXXX.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS's standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE ET-2
RESIDENTIAL SERVICE TIME-OF-USE
TIME ADVANTAGE 7PM-NOON

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatthour meter.

This schedule is not applicable to breakdown, standby, supplemental or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services) and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates, plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $ 0.579 per day

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 0.21275 per kWh during On-Peak hours, plus $ 0.06848 per kWh during Off-Peak hours	$0.17260 per kWh during On-Peak hours, plus $0.06846 per kWh during Off-Peak hours

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge: $ 0.260 per day

Revenue Cycle Service Charges:

Metering $ 0.204 per day

Meter Reading $ 0.038 per day

RATES (cont)

Unbundled Components (cont)

Billing	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh
Delivery Charge:	$ 0.02932	per kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.18178 per kWh during On-Peak hours, plus $0.03751 per kWh during Off-Peak hours	$0.14163 per kWh during On-Peak hours, plus $0.03749 per kWh during Off-Peak hours

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

TIME PERIODS

The On-Peak time period for this rate schedule is 12 noon to 7 p.m. Monday through Friday excluding the holidays listed below. All hours not included in the On-Peak time period shall be Off-Peak hours.

The following holidays are Off-Peak: New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25). When any holiday listed above falls on a Saturday, the preceding Friday will be recognized as an off-peak period. When any holiday listed above falls on a Sunday, the following Monday will be recognized as an off-peak period. Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

ADJUSTMENTS (cont)

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE ECT-1R
RESIDENTIAL SERVICE
TIME-OF-USE WITH DEMAND CHARGE
COMBINED ADVANTAGE RATE

FROZEN

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt/kilowatthour meter.

Additionally, this rate schedule is applicable only to those customers being served on the Company's Rate Schedule ECT-1R prior to January 1, 2010.

This schedule is not applicable to breakdown, standby, supplemental or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services), and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates, plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $0.579 per day

Demand Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$14.039 per On-Peak kW	$9.648 per On-Peak kW

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.07191 per kWh during On-Peak hours, plus $0.03753 per kWh during Off-Peak hours	$0.05288 per kWh during On-Peak hours, plus $0.03573 per kWh during Off-Peak hours

RATES (cont)

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge:	$ 0.260	per day
Revenue Cycle Service Charges:		
Metering	$ 0.204	per day
Meter Reading	$ 0.038	per day
Billing	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh

Delivery Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$4.001 per On-Peak kW, plus $0.01319 per kWh	$2.190 per On-Peak kW, plus $0.01634 per kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$10.038 per On-Peak kW, plus $0.05707 per kWh during On-Peak hours, plus $0.02269 per kWh during Off-Peak hours	$7.458 per On-Peak kW, plus $0.03489 per kWh during On-Peak hours, plus $0.01774 per kWh during Off-Peak hours

FROZEN

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

TIME PERIODS

The standard Company On-Peak time period for residential rate schedules is 9 a.m. to 9 p.m. Monday through Friday. All hours not included in the On-Peak time period shall be Off-Peak hours.

Mountain Standard Time shall be used in the application of this rate schedule.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be based on the average kW supplied during the 60-minute period of maximum use during On-Peak hours, as determined from readings of the Company's meter.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663 Arizona Corporation Commission Decision No. 71448 and XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS's standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

FROZEN

RATE SCHEDULE ECT-2
RESIDENTIAL SERVICE
TIME-OF-USE WITH DEMAND CHARGE
COMBINED ADVANTAGE 7PM-NOON

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt/kilowatthour meter.

This schedule is not applicable to breakdown, standby, supplemental or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services) and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates, plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $ 0.579 per day

Demand Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$14.060 per On-Peak kW	$9.653 per On-Peak kW

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.08676 per kWh during On-Peak hours, plus $0.03975 per kWh during Off-Peak hours	$0.05498 per kWh during On-Peak hours, plus $0.03881 per kWh during Off-Peak hours

RATES (cont)

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge:	$ 0.260	per day
Revenue Cycle Service Charges:		
Metering	$ 0.204	per day
Meter Reading	$ 0.038	per day
Billing	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh

Delivery Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$4.004 per On-Peak kW, plus $0.01332 per kWh	$2.191 per On-Peak kW, plus $0.01634 per kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$10.056 per On-Peak kW, plus $0.07179 per kWh during On-Peak hours, plus $0.02478 per kWh during Off-Peak hours	$7.462 per On-Peak kW, plus $0.03699 per kWh during On-Peak hours, plus $0.02082 per kWh during Off-Peak hours

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

TIME PERIODS

The On-Peak time period for this rate schedule is 12 noon to 7 p.m. Monday through Friday excluding the holidays listed below. All hours not included in the On-Peak time period shall be Off-Peak hours. The following holidays are Off-Peak: New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25). When any holiday listed above falls on a Saturday, the preceding Friday will be recognized as an

TIME PERIODS (cont)

off-peak period. When any holiday listed above falls on a Sunday, the following Monday will be recognized as an off-peak period.

Mountain Standard Time shall be used in the application of this rate schedule.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be based on the average kW supplied during the 60-minute period of maximum use during the customer's On-Peak hours, as determined from readings of the Company's meter.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE ET-SP
RESIDENTIAL SERVICE TIME-OF-USE
TIME ADVANTAGE SUPER PEAK 7PM-NOON

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer electric service required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter. This rate requires the customer to have an Advanced Metering Infastructure meter, or AMI, in place at time of service. A customer may not simultaneously participate in Schedule ET-SP and another demand response rate or program,

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatthour meter.

This schedule is not applicable to breakdown, standby, supplemental or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services) and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates, plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $ 0.579 per day

Energy Charge:

June – August Billing Cycles (Super Peak Summer)
$0.46282 per kWh during Super-Peak hours, plus $0.21282 per kWh during On-Peak hours, plus $0.05911 per kWh during Off-Peak hours

May, September, and October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.21282 per kWh during On-Peak hours, plus $0.05911 per kWh during Off-Peak hours	$0.17265 per kWh during On-Peak hours, plus $0.05908 per kWh during Off-Peak hours

RATES (cont)

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge:	$ 0.260	per day
Revenue Cycle Service Charges:		
Metering	$ 0.204	per day
Meter Reading	$ 0.038	per day
Billing	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh
Delivery Charge:	$ 0.02933	per kWh

Generation Charge:

June – August Billing Cycles (Super Peak Summer)
$0.43184 per kWh during Super-Peak hours, plus $0.18184 per kWh during On-Peak hours, plus $0.02813 per kWh during Off-Peak hours

May, September, and October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.18184 per kWh during On-Peak hours, plus $0.02813 per kWh during Off-Peak hours	$0.14167 per kWh during On-Peak hours, plus $0.02810 per kWh during Off-Peak hours

TIME PERIODS

The Super-Peak time period is 3 p.m. to 6 p.m. and the On-Peak time period is 12 noon to 3 p.m. and 6 p.m. to 7 p.m., during the Super Peak Summer months Monday through Friday excluding the holidays listed below. The On-Peak time period during Summer and Winter months for this rate schedule is 12 noon to 7 p.m. Monday through Friday excluding the holidays listed below. All hours not included in the Super-Peak or On-Peak time periods shall be Off-Peak hours for all seasons.

The following holidays are Off-Peak: New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25). When any holiday listed above falls on a Saturday, the preceding Friday will be recognized as an off-peak period. When any holiday listed above falls on a Sunday, the following Monday will be recognized as an off-peak period. Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-12, LOW INCOME RESIDENTIAL SERVICE STANDARD RATE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter. For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to a water heating or space heating rate schedule no longer in effect, the electric service measured by such meters shall be combined for billing purposes. Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is only available for customers that are enrolled in the E-3 Energy Support Program or the E-4 Medical Care Equipment Support Program. This schedule is not applicable to breakdown, standby, supplemental or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services), and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $ 0.345 per day

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.08322 per kWh for the first 400 kWh, plus $0.12061 per kWh for the next 400 kWh, plus $0.14396 per kWh for all additional kWh	$0.08070 per kWh

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge: $ 0.105 per day

RATES (cont)

Unbundled Components (cont)

Revenue Cycle Service Charges:		
Metering	$0.150	per day
Meter Reading	$0.038	per day
Billing	$0.052	per day
System Benefits Charge:	$0.00165	per kWh
Delivery Charge:	$0.03410	per kWh

Generation Charges:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.04747 per kWh for the first 400 kWh, plus $0.08486 per kWh for the next 400 kWh, plus $0.10821 per kWh for all additional kWh	$0.04495 per kWh

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

ADJUSTMENTS (cont)

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE ET-1, LOW INCOME RESIDENTIAL SERVICE TIME-OF-USE TIME ADVANTAGE RATE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatthour meter.

Additionally, this rate schedule is applicable only to those customers being served on the Company's Rate Schedule ET-1 prior to January 1, 2010. This schedule is only available for customers that are enrolled in the E-3 Energy Support Program or the E-4 Medical Care Equipment Support Program. This schedule is not applicable to breakdown, standby, supplemental or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services, and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates, plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $0.579 per day

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 0.15045 per kWh during On-Peak hours, plus $ 0.06020 per kWh during Off-Peak hours	$0.11439 per kWh during On-Peak hours, plus $0.05721 per kWh during Off-Peak hours

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge: $ 0.260 per day

FROZEN

RATES (cont)

Unbundled Components (cont)

Revenue Cycle Service Charges:

Metering	$ 0.204	per day
Meter Reading	$ 0.038	per day
Billing	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh
Delivery Charge:	$ 0.02672	per kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.12208 per kWh during On-Peak hours, plus $0.03183 per kWh during Off-Peak hours	$0.08602 per kWh during On-Peak hours, plus $0.02884 per kWh during Off-Peak hours

FROZEN

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

TIME PERIODS

The standard Company On-Peak time period for residential rate schedules is 9 a.m. to 9 p.m. Monday through Friday. All hours not included in the On-Peak time period shall be Off-Peak hours.

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

ADJUSTMENTS (cont)

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. XXXX.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. XXXX.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. XXXX.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

FROZEN

RATE SCHEDULE ET-2, LOW INCOME RESIDENTIAL SERVICE TIME-OF-USE TIME ADVANTAGE 7PM-NOON

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatthour meter.

This schedule is only available for customers that are enrolled in the E-3 Energy Support Program or the E-4 Medical Care Equipment Support Program. This schedule is not applicable to breakdown, standby, supplemental or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services) and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates, plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $0.579 per day

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 0.19301 per kWh during On-Peak hours, plus $ 0.06384 per kWh during Off-Peak hours	$0.15657 per kWh during On-Peak hours, plus $0.06382 per kWh during Off-Peak hours

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge: $ 0.260 per day

Revenue Cycle Service Charges:

Metering $ 0.204 per day

Meter Reading $ 0.038 per day

RATES (Cont)

Unbundled Components (cont)

Billing	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh
Delivery Charge:	$ 0.02693	per kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.16443 per kWh during On-Peak hours, plus $0.03526 per kWh during Off-Peak hours	$0.12799 per kWh during On-Peak hours, plus $0.03524 per kWh during Off-Peak hours

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

TIME PERIODS

The On-Peak time period for this rate schedule is 12 noon to 7 p.m. Monday through Friday excluding the holidays listed below. All hours not included in the On-Peak time period shall be Off-Peak hours.

The following holidays are Off-Peak: New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25). When any holiday listed above falls on a Saturday, the preceding Friday will be recognized as an off-peak period. When any holiday listed above falls on a Sunday, the following Monday will be recognized as an off-peak period. Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

ADJUSTMENTS (Cont)

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE ECT-1R, LOW INCOME RESIDENTIAL SERVICE TIME-OF-USE WITH DEMAND CHARGE COMBINED ADVANTAGE RATE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt/kilowatthour meter.

Additionally, this rate schedule is applicable only to those customers being served on the Company's Rate Schedule ECT-1R prior to January 1, 2010. This schedule is only available for customers that are enrolled in the E-3 Energy Support Program or the E-4 Medical Care Equipment Support Program. This schedule is not applicable to breakdown, standby, supplemental or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services), and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates, plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $ 0.579 per day

Demand Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$14.596 per On-Peak kW	$ 10.030 per On-Peak kW

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 0.07453 per kWh during On-Peak hours, plus $ 0.0388 per kWh during Off-Peak hours	$ 0.05488 per kWh during On-Peak hours, plus $ 0.03707 per kWh during Off-Peak hours

FROZEN

RATES (cont)

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge:	$ 0.260	per day
Revenue Cycle Service Charges:		
Metering	$ 0.204	per day
Meter Reading	$ 0.038	per day
Billing	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh

Delivery Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$4.160 per On-Peak kW, plus $0.01357 per kWh	$ 2.277 per On-Peak kW, plus $0.01698 per kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$10.436 per On-Peak kW, plus $0.05931 per kWh during On-Peak hours, plus $0.02358 per kWh during Off-Peak hours	$7.753 per On-Peak kW, plus $0.03625 per kWh during On-Peak hours, plus $0.01844 per kWh during Off-Peak hours

FROZEN

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

TIME PERIODS

The standard Company On-Peak time period for residential rate schedules is 9 a.m. to 9 p.m. Monday through Friday. All hours not included in the On-Peak time period shall be Off-Peak hours.

Mountain Standard Time shall be used in the application of this rate schedule.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be based on the average kW supplied during the 60-minute period of maximum use during On-Peak hours, as determined from readings of the Company's meter.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

FROZEN

RATE SCHEDULE ECT-2, LOW INCOME RESIDENTIAL SERVICE TIME-OF-USE WITH DEMAND CHARGE COMBINED ADVANTAGE 7PM-NOON

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service, except as stated below, required for residential purposes in individual private dwellings and in individually metered apartments when such service is supplied at one site through one point of delivery and measured through one meter.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt/kilowatthour meter.

This schedule is only available for customers that are enrolled in the E-3 Energy Support Program or the E-4 Medical Care Equipment Support Program. This schedule is not applicable to breakdown, standby, supplemental or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 or 120/208 as may be selected by customer subject to availability at the customer's site). Three phase service may be furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services) and is required for motors of an individual rated capacity of 7-1/2 HP or more.

RATES

The customer's bill shall be computed at the following rates, plus any adjustments incorporated in this schedule:

Bundled Standard Offer Service

Basic Service Charge: $ 0.579 per day

Bundled Standard Offer Service (cont)

Demand Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$12.930 per On-Peak kW	$8.878 per On-Peak kW

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.07906 per kWh during On-Peak hours, plus $0.03596 per kWh during Off-Peak hours	$0.04993 per kWh during On-Peak hours, plus $0.03509 per kWh during Off-Peak hours

RATES (cont)

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge:	$ 0.260	per day
Revenue Cycle Service Charges:		
Metering	$ 0.204	per day
Meter Reading	$ 0.038	per day
Billing	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh

Delivery Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$3.682 per On-Peak kW, plus $0.01222 per kWh	$2.015 per On-Peak kW, plus $0.01499 per kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$9.248 per On-Peak kW, plus $0.06519 per kWh during On-Peak hours, plus $0.02209 per kWh during Off-Peak hours	$6.863 per On-Peak kW, plus $0.03329 per kWh during On-Peak hours, plus $0.01845 per kWh during Off-Peak hours

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

TIME PERIODS

The On-Peak time period for this rate schedule is 12 noon to 7 p.m. Monday through Friday excluding the holidays listed below. All hours not included in the On-Peak time period shall be Off-Peak hours.

The following holidays are Off-Peak: New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25). When any holiday listed above falls on a Saturday, the preceding Friday will be recognized as an off-peak period. When any holiday listed above falls on a Sunday, the following Monday will be recognized as an off-peak period.

TIME PERIODS (Cont)

Mountain Standard Time shall be used in the application of this rate schedule.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be based on the average kW supplied during the 60-minute period of maximum use during the customer's On-Peak hours, as determined from readings of the Company's meter.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

Any applicable contract period will be set forth in APS' standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE RIDER SCHEDULE E-3
RESIDENTIAL SERVICE
ENERGY SUPPORT PROGRAM

AVAILABILITY

This rate rider schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served. Customers may not receive discounts under this schedule and Rate Rider Schedule E-4 Medical Support Care Program concurrently.

APPLICATION

This rate rider schedule is applicable to all Standard Offer and Direct Access electric service billed under a residential rate schedule, where the customer has qualified for this rate as specified in the Company's Plan for Administration of the Residential Energy Support Program pursuant to Arizona Corporation Commission Decision Nos. 55931, 56680 and 69663. All provisions of the applicable retail rate schedule will apply except as modified herein.

RATES

The total bill as calculated according to the applicable retail rate schedule before taxes, regulatory assessment and franchise fees, excluding amounts billed under Adjustment Schedule TCA-1, will be discounted by 25% with a maximum discount of $18.

RATE RIDER SCHEDULE E-4
RESIDENTIAL SERVICE
MEDICAL CARE EQUIPMENT SUPPORT PROGRAM

AVAILABILITY

This rate rider schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served. Customers may not receive discounts under this schedule and Rate Rider Schedule E-3 Energy Support Program concurrently.

APPLICATION

This rate rider schedule is applicable to all Standard Offer and Direct Access electric service billed under a residential rate schedule, where the customer has qualified for this rate as specified in the Company's Plan for Administration of the Medical Care Equipment Program pursuant to Arizona Corporation Commission Decision Nos. 59222 and 69663. All provisions of the applicable retail rate schedule will apply except as modified herein.

RATES

The total bill as calculated according to the applicable retail rate schedule before taxes, regulatory assessment and franchise fees, excluding amounts billed under Adjustment Schedule TCA-1, will be discounted by 25% with a maximum discount of $36.

RATE RIDER SCHEDULE CPP-RES
CRITICAL PEAK PRICING – RESIDENTIAL

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

The Rate Schedule CPP-RES is available to residential retail Standard Offer customers. This rate requires the customer to have an Advanced Metering Infastructure meter, or AMI, in place at time of service. All provisions of the customer's otherwise applicable rate schedule will apply in addition to the charges in Schedule CPP-RES. Schedule CPP-RES is available for a period of two years from the initial availability.

A customer may not simultaneously participate in Schedule CPP-RES and another demand response rate or program, including Schedule ET-SP. A customer may participate in Schedule CPP-RES and a net metering rate schedule, subject to meter availability. However, any customer generation in excess of load during a CPP Event will be netted according to the customer's otherwise applicable rate schedule and will not be netted against usage during a subsequent CPP Event.

RATES

A. Critical Peak Price — $ 0.250000 per kWh
Critical Peak Price applies to kWh usage during a CPP Event.

B. Energy Discount

All residential customers	$ (0.012143)	per kWh

Energy Discount applies to Customer's total monthly kWh in the months of June through September.

CONDITIONS

A. CPP Events: CPP Events may be invoked by the Company for the period 2 p.m. to 7 p.m., weekdays (Monday through Friday) during June through September. Holidays are excluded, which include Independence Day (July 4th) and Labor Day (first Monday in September). A CPP Event can be triggered by severe weather, high load, high wholesale prices, or a major generation or transmission outage, as determined by the Company.

B. Number and Duration of CPP Events: The Company will invoke a minimum of 6 and a maximum of 18 CPP Events per calendar year, for 5 hours per event and 90 hours per year.

C. CPP Event Notification/Communication: Customers shall be notified of a CPP Event in advance by 4:00 PM the day prior through a phone message, e-mail, or text message. Receipt of such notice is the responsibility of the participating customer.

D. CPP Event Cancellation: Once a CPP event alert has been initiated, there are no conditions that would warrant the critical event to be cancelled.

RATE RIDER SCHEDULE PTR-RES
RESIDENTIAL SERVICE
PEAK TIME REBATE EXPERIMENT PROGRAM

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

The Rider Rate Schedule PTR-RES is available to residential retail Standard Offer customers served under Rate Schedule ET-2. This rate requires the customer to have an Advanced Metering Infastructure meter, or AMI, in place at time of service. All provisions of Rate Schedule ET-2 will apply in addition to the rates and provisions in Schedule PTR-RES. Schedule PTR-RES is a pilot program and is available for a period of two years from its effective date. Participation shall be limited to the first 2,000 customers. A customer may not simultaneously participate in Schedule PTR-RES and another demand response rate or program, including Rate Schedule ET-SP.

DESCRIPTION

Under this program, the Company incents customers to reduce their electrical usage during critical hours when load is difficult or expensive to serve. During these ciritcal times, the Company may declare an event (PTR Event) where the customer receives a rebate for the amount of energy that they reduced. Such rebates will be credited on their monthly electric bill.

RATES

The Credit Rate shall apply to the Energy Reduction (kWh) during a PTR Event, as determined by the Company.

Credit Rate	$0.250000	per kWh

DETERMINATION OF LOAD REDUCTION

A. The Energy Reduction reduction during a PTR Event will be determined using a customer baseline load (CBL) method, which estimates how much electricity a customer would have used had they not reduced their usage in response to a PTR event. The Energy Reduction is determined by subtracting the actual metered load from the CBL for all hours during a PTR event.

B. The CBL shall be the customer's usage (kWh) from 2 p.m. to 7 p.m., averaged over the three highest days of the preceding ten non-holiday, non-event, weekdays prior to the event. The highest days shall be determined by the highest total consumption from 2 p.m. to 7 p.m.

CONDITIONS

A. PTR Events: PTR Events may be invoked by the Company for the period 2 p.m. to 7 p.m., weekdays (Monday through Friday) during June through September. Holidays are excluded, which include Independence Day (July 4th) and Labor Day (first Monday in September). A PTR Event can be called based on severe weather, high load, high wholesale prices, or a major generation or transmission outage, as determined by the Company.

B. Number and Duration of PTR Events: The Company will invoke a minimum of 6 and a maximum of 18 PTR Events and 90 event hours, based on five hours per event, per calendar year.

C. PTR Event Notification/Communication: The Company shall notify customers of a PTR Event by 4:00 PM the prior day through a phone message, e-mail, or text message. Receipt of such notice is the responsibility of the participating customer.

D. PTR Event Cancellation: Once a PTR event alert has been initiated, there are no conditions that shall warrant the event to be cancelled.

NET METERING

A customer may participate in Schedule PTR-RES and a net metering rate schedule, subject to meter availability. However, any customer generation in excess of load during a PTR Event will be netted according to the customer's otherwise applicable rate schedule and will not be netted against usage during a subsequent PTR Event.

General Service

RATE SCHEDULE E-30
GENERAL SERVICE
EXTRA SMALL UNMETERED

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access electric service required where demand and energy requirements are constant, subject to the limitations set forth in the Special Provisions of this schedule. Billing quantities must be subject to accurate determination without the use of metering equipment, and service must be supplied at a single point of delivery.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single phase, 60 Hertz, at a single standard voltage (120/240 volts). The cost of service extension shall include transformation equipment, if required.

RATES

The bill shall be computed at the following rates, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge: $ 0.305 per day

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.14777 per kWh	$0.13212 per kWh

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Components

Basic Service Charge: $ 0.267 per day

Revenue Cycle Service Charges:
Billing: $ 0.038 per day

System Benefits Charge: $ 0.00165 per kWh

Delivery Charge: $ 0.05354 per kWh

RATES (cont)

Unbundled Components (cont)

Generation Charge:

May - October Billing Cycles (Summer)	November - April Billing Cycles (Winter)
$0.09258 per kWh	$0.07693 per kWh

DIRECT ACCESS

The bill for Direct Access customers will consist of the Unbundled Components Basic Service Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663 Arizona Corporation Commission Decision No. 71448 XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to 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 APS 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.

SPECIAL PROVISIONS

1. Electric services being served on the Company's Rate Schedule E-30 prior to April 1, 2005 will continue to be served under this rate schedule; however, services eligible for this rate schedule after that date must meet the demand and energy requirements set forth in the following Special Provisions.

2. This rate schedule is applicable only to loads where monthly demand (kW) and energy (kWh) requirements remain constant. Monthly demand and energy requirements may not exceed 1.44 kW (12 amperes) or 1,095 kWh at 120 volts, or 2.9 kW (12 amperes) or 2,117 kWh at 240 volts. Determination of fixed monthly energy usage will be derived from the manufacturer's nameplate rating of the equipment and based on an average 730 hour month.

3. Prior written approval by an authorized Company representative is required before service is implemented under this rate schedule.

4. Prior written approval by an authorized Company representative is required for any change in loads. An unauthorized load change will automatically disqualify that customer from service under this rate schedule.

5. The Company shall have the right to inspect the customer's load facilities at any time to ensure compliance with all provisions of this rate schedule.

6. Service must be supplied at one site through one point of delivery as specified by an individual customer contract.

CONTRACT PERIOD

Any applicable contract period will be set forth in the Company's standard agreement for service.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-32 XS
EXTRA SMALL GENERAL SERVICE (0 kW - 20 kW)

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is 20 kW per month or less.

The Company initially will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Average Monthly Maximum Demand, as determined by the Company.

The Customer will be billed on Schedule E-32 S or E-32 XS depending on the Monthly Maximum Demand for each billing cycle.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP. Service under this schedule is generally provided at secondary voltage or primary voltage when the customer owns the distribution transformer(s).

RATES

The bill shall be computed at the following rates, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$	0.658	per day, or
For service through Instrument-Rated Meters:	$	1.328	per day, or
For service at Primary Voltage:	$	3.477	per day

RATES (cont)

Bundled Standard Offer Service (cont)

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
For Secondary Service: $0.13209 per kWh for the first 5,000 kWh, plus $0.07001 per kWh for all additional kWh, or	For Secondary Service: $0.11402 per kWh for the first 5,000 kWh, plus $0.05193 per kWh for all additional kWh, or
For Primary Service: $0.12877 per kWh for the first 5,000 kWh, plus $0.06668 per kWh for all additional kWh	For Primary Service: $0.11069 per kWh for the first 5,000 kWh, plus $0.04861 per kWh for all additional kWh

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.129	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.414	per day, or
Instrument-Rated Meters:	$ 1.084	per day, or
Primary:	$ 3.233	per day

These daily metering charges apply to typical installations. Customers requiring specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

Meter Reading:	$ 0.038	per day
Billing:	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh

RATES (cont)

Unbundled Standard Offer Service (cont)

Delivery Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
For Secondary Service: $0.04221 per kWh for the first 5,000 kWh, plus $0.01327 per kWh for all additional kWh, or	For Secondary Service: $0.04213 per kWh for the first 5,000 kWh, plus $0.01317 per kWh for all additional kWh, or
For Primary Service: $0.03889 per kWh for the first 5,000 kWh, plus $0.00994 per kWh for all additional kWh	For Primary Service: $0.03880 per kWh for the first 5,000 kWh, plus $0.00985 per kWh for all additional kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.08823 per kWh for the first 5,000 kWh, plus $0.05509 per kWh for all additional kWh	$0.07024 per kWh for the first 5,000 kWh, plus $0.03711 per kWh for all additional kWh

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment. Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, including determination of Monthly Maximum Demands, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month as determined from readings of the Company's meter.

The Average Monthly Maximum Demand shall equal the average of the Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum kW provided by the Customer and approved by the Company.

ADJUSTMENTS

1 The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2 The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

3 The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjutment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

For customers with monthly maximum demands up to 20 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-32 S
SMALL GENERAL SERVICE (21 kW – 100 kW)

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 20 kW and less than or equal to 100 kW per month.

The Company will place the Customer on the Applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination. The Company may also place the Customer on the Applicable Rate Schedule during the year, if the Customer has experienced a significant and permanent change in load as determined by the Company. Such placement will be based on available information.

The Customer will be billed on Schedule E-32 S or E-32 XS depending on the Monthly Maximum Demand for each billing cycle.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services. This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP. Service under this schedule is generally provided at secondary voltage or primary voltage when the customer owns the distribution transformer(s).

RATES

The bill shall be computed at the following rates, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 0.658	per day, or
For service through Instrument-Rated Meters:	$ 1.328	per day, or
For service at Primary Voltage:	$ 3.477	per day

RATES (cont)

Bundled Standard Offer Service (cont)

Demand Charge:

Secondary Service:	$ 8.327	per kW for the first 100 kW, plus
	$ 3.665	per kW for all additional kW, or
Primary Service:	$ 7.607	per kW for the first 100 kW, plus
	$ 2.947	per kW for all additional kW, or

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.10655 per kWh for the first 200 kWh per kW, plus $0.06209 per kWh for all additional kWh	$0.08891 per kWh for the first 200 kWh per kW, plus $0.04445 per kWh for all additional kWh

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.129	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.414	per day, or
Instrument-Rated Meters:	$ 1.084	per day, or
Primary:	$ 3.233	per day

These daily metering charges apply to typical installations. Customers requiring specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

Meter Reading:	$ 0.038	per day
Billing:	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh
Delivery Charge:		
Secondary Service:	$ 8.327	per kW for the first 100 kW, plus
	$ 3.665	per kW for all additional kW, plus
	$ 0.00011	per kWh, or
Primary Service:	$ 7.607	per kW for the first 100 kW, plus
	$ 2.947	per kW for all additional kW, plus
	$ 0.00011	per kWh

RATES (cont)

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.10479 per kWh for the first 200 kWh per kW, plus $0.06033 per kWh for all additional kWh	$0.08715 per kWh for the first 200 kWh per kW, plus $0.04269 per kWh for all additional kWh

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by
the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, including determination of Monthly Maximum Demands, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month as determined from readings of the Company's meter.

The Average Monthly Maximum Demand shall equal the average of the Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum kW provided by the Customer and approved by the Company.

ADJUSTMENTS

1 The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2 The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

3 The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

For customers with monthly maximum demands greater than 20 and less than or equal to 100 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-32 M
MEDIUM GENERAL SERVICE (101 kW - 400 kW)

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 100 kW and less than or equal to 400 kW per month.

The Company will place the Customer on the Applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination. The Company may also place the Customer on the Applicable Rate Schedule during the year, if the Customer has experienced a significant and permanent change in load as determined by the Company. Such placement will be based on available information.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services. This schedule is not applicable to breakdown, standby, supplemental, residential or resale service nor to service for which Rate Schedule E-34 is applicable.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP. Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 0.658	per day, or
For service through Instrument-Rated Meters:	$ 1.328	per day, or
For service at Primary Voltage:	$ 3.477	per day, or
For service at Transmission Voltage:	$ 26.855	per day

RATES (cont)

Bundled Standard Offer Service (cont)

Demand Charge:

Secondary Service:	$ 8.294	per kW for the first 100 kW, plus
	$ 3.644	per kW for all additional kW, or
Primary Service:	$ 7.578	per kW for the first 100 kW, plus
	$ 2.927	per kW for all additional kW, or
Transmission Service:	$ 5.546	per kW for the first 100 kW, plus
	$ 0.895	per kW for all additional kW

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.10628 per kWh for the first 200 kWh per kW, plus $0.06192 per kWh for all additional kWh	$0.08867 per kWh for the first 200 kWh per kW, plus $0.04433 per kWh for all additional kWh

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.129	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.414	per day, or
Instrument-Rated Meters:	$ 1.084	per day, or
Primary:	$ 3.233	per day, or
Transmission:	$ 26.611	per day

These daily metering charges apply to typical installations. Customers requiring specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 Kv). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

Meter Reading:	$ 0.038	per day
Billing:	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh

RATES (cont)

Unbundled Standard Offer Service (cont)

Delivery Charge:

Secondary Service:	$ 8.294	per kW for the first 100 kW, plus
	$ 3.644	per kW for all additional kW, plus
	$ 0.00011	per kWh, or
Primary Service:	$ 7.578	per kW for the first 100 kW, plus
	$ 2.927	per kW for all additional kW, plus
	$ 0.00011	per kWh, or
Transmission Service:	$ 5.546	per kW for the first 100 kW, plus
	$ 0.895	per kW for all additional kW, plus
	$ 0.00011	per kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.10452 per kWh for the first 200 kWh per kW, plus $0.06016 per kWh for all additional kWh	$0.08691 per kWh for the first 200 kWh per kW, plus $0.04257 per kWh for all additional kWh

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment. Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, including determination of Monthly Maximum Demands, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month as determined from readings of the Company's meter.

The Average Monthly Maximum Demand shall equal the average of the Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum kW provided by the Customer and approved by the Company.

ADJUSTMENTS

1 The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2 The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

3 The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

For customers with monthly maximum demands greater than 100 and less than or equal to 400 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 400 kW per month.

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination. The Company may also place the Customer on the Applicable Rate Schedule during the year, if the Customer has experienced a significant and permanent change in load as determined by the Company. Such placement will be based on available information.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service nor to service for which Rate Schedule E-34 is applicable.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP. Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 0.658	per day, or
For service through Instrument-Rated Meters:	$ 1.328	per day, or
For service at Primary Voltage:	$ 3.477	per day, or
For service at Transmission Voltage:	$ 26.855	per day

RATES (cont)

Bundled Standard Offer Service (cont)

Demand Charge:

Secondary Service:	$ 16.899	per kW for the first 100 kW, plus
	$ 12.313	per kW for all additional kW, or
Primary Service:	$ 16.188	per kW for the first 100 kW, plus
	$ 11.605	per kW for all additional kW, or
Transmission Service:	$ 13.188	per kW for the first 100 kW, plus
	$ 9.601	per kW for all additional kW.

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$0.05935 per kWh	$0.04249 per kWh

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.129	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.414	per day, or
Instrument-Rated Meters:	$ 1.084	per day, or
Primary:	$ 3.233	per day, or
Transmission:	$ 26.611	per day

These daily metering charges apply to typical installations. Customers requiring specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

Meter Reading:	$ 0.038	per day
Billing:	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh

RATES (cont)

Unbundled Standard Offer Service (cont)

Delivery Charge:

Secondary Service:	$ 8.145	per kW for the first 100 kW, plus
	$ 3.559	per kW for all additional kW, plus
	$ 0.00011	per kWh, or
Primary Service:	$ 7.434	per kW for the first 100 kW, plus
	$ 2.851	per kW for all additional kW, plus
	$ 0.00011	per kWh, or
Transmission Service:	$ 4.434	per kW for the first 100 kW, plus
	$ 0.847	per kW for all additional kW, plus
	$ 0.00011	per kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$8.754 per kW, plus $0.05759 per kWh	$8.754 per kW, plus $0.04073 per kWh

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

MINIMUM

The bill for service under this rate schedule shall not be less than the applicable Bundled Standard Offer Service Basic Service Charge plus the applicable Bundled Standard Offer Service Demand Charge for each kW as determined herein.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

POWER FACTOR (cont)

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be the greater of the following:

1. The average kW supplied during the 15-minute period (or other period as specified by an individual customer contract) of maximum use during the month, as determined from readings of the Company's meter.

2. 80% of the highest kW measured during the six (6) summer billing months (May-October) of the twelve (12) months ending with the current month.

3. The minimum kW specified in the agreement for service or individual contract.

For the purpose of placement on this rate, the Average Monthly Maximum Demand shall equal the average of the Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum kW provided by the Customer and approved by the Company.

The Monthly Maximum Demand shall be based on the average kW supplied during the 15-minute period of maximum use during the month as determined from readings of the Company's meter.

ADJUSTMENTS

1 The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2 The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

3 The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

ADJUSTMENTS (cont)

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

For customers with monthly maximum demands greater than 400 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-32TOU XS
EXTRA SMALL GENERAL SERVICE (0 kW - 20 kW)
TIME OF USE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is 20 kW per month or less.

The Company will initially place the Customer on the applicable Rate Schedule E-32TOU XS, E-32TOU S, E-32 TOU M, or E-32TOU L based on the Average Monthly Maximum Demand, as determined by the Company.

The Customer will be billed on Schedule E-32TOU S or E-32TOU XS depending on the On-peak Monthly Maximum Demand for each billing cycle.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt/kilowatt-hour meter.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

Service under this schedule is generally provided at secondary voltage or primary voltage when the customer owns the distribution transformer(s).

RATES

The bill shall be computed at the following rates, plus any adjustments incorporated in this rate schedule:

Basic Service Charge:

For service through Self-Contained Meters	$ 0.658	per day, or
For service through Instrument-Rated Meters:	$ 1.328	per day, or
For service at Primary Voltage:	$ 3.477	per day

RATES (cont)

Bundled Standard Offer Service

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
For Secondary Service: $ 0.16793 per kWh for the first 5,000 On-Peak kWh, plus $ 0.08008 per kWh for all additional On-Peak kWh, plus $ 0.12303 per kWh for the first 5,000 Off-Peak kWh, plus $ 0.04082 per kWh for all additional Off-Peak kWh, or	For Secondary Service: $ 0.15020 per kWh for the first 5,000 On-Peak kWh, plus $ 0.06231 per kWh for all additional On-Peak kWh, plus $ 0.10527 per kWh for the first 5,000 Off-Peak kWh, plus $ 0.02787 per kWh for all additional Off-Peak kWh, or
For Primary Service: $ 0.16442 per kWh for the first 5,000 On-Peak kWh, plus $ 0.07574 per kWh for all additional On-Peak kWh, plus $ 0.11951 per kWh for the first 5,000 Off-Peak kWh, plus $ 0.03731 per kWh for all additional Off-Peak kWh	For Primary Service: $ 0.14668 per kWh for the first 5,000 On-Peak kWh, plus $ 0.05797 per kWh for all additional On-Peak kWh, plus $ 0.10176 per kWh for the first 5,000 Off-Peak kWh, plus $ 0.02435 per kWh for all additional Off-Peak kWh

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.129	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.414	per day, or
Instrument-Rated Meters:	$ 1.084	per day, or
Primary:	$ 3.233	per day

These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

Meter Reading:	$ 0.038	per day
Billing:	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh

RATES (cont)

Unbundled Standard Offer Service (cont)

Delivery Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
For Secondary Service: $ 0.05308 per kWh for the first 5,000 On-Peak kWh, plus $ 0.01379 per kWh for all additional On-Peak kWh, plus $ 0.04374 per kWh for the first 5,000 Off-Peak kWh plus $ 0.01008 per kWh for all additional Off-Peak kWh, or	For Secondary Service: $ 0.05300 per kWh for the first 5,000 On-Peak kWh, plus $ 0.01367 per kWh for all additional On-Peak kWh, plus $ 0.04364 per kWh for the first 5,000 Off-Peak kWh plus $ 0.01000 per kWh for all additional Off-Peak kWh, or
For Primary Service: $ 0.04957 per kWh for the first 5,000 On-Peak kWh, plus $ 0.00945 per kWh for all additional On-Peak kWh, plus $ 0.04022 per kWh for the first 5,000 Off-Peak kWh plus $ 0.00657 per kWh for all additional Off-Peak kWh	For Primary Service: $ 0.04948 per kWh for the first 5,000 On-Peak kWh, plus $ 0.00933 per kWh for all additional On-Peak kWh, plus $ 0.04013 per kWh for the first 5,000 Off-Peak kWh plus $ 0.00648 per kWh for all additional Off-Peak kWh

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 0.11320 per kWh for the first 5,000 On-Peak kWh, plus $ 0.06464 per kWh for all additional On-Peak kWh, plus $ 0.07764 per kWh for the first 5,000 Off-Peak kWh, plus $ 0.02909 per kWh for all additional Off-Peak kWh	$ 0.09555 per kWh for the first 5,000 On-Peak kWh, plus $ 0.04699 per kWh for all additional On-Peak kWh, plus $ 0.05998 per kWh for the first 5,000 Off-Peak kWh, plus $ 0.01622 per kWh for all additional Off-Peak kWh

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

POWER FACTOR (cont)

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the On-Peak and Off-Peak periods during the billing period, as determined from readings of the Company's meter.

Monthly Maximum Demand will be based on the highest average kW supplied during the 15-minute period during either the On-Peak or Off-Peak hours of the billing period, as determined from readings of the Company's meter.

On-peak Monthly Maximum Demand will be based on the highest average kW supplied during the 15-minute period during the On-peak hours of the billing period, as determined from readings of the Company's meter.

The Average Monthly Maximum Demand shall equal the average of the On-peak Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the On-peak Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum On-peak kW provided by the Customer and approved by the Company.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

On-Peak hours:	11:00 am – 9:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

ADJUSTMENTS (cont)

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

For customers with monthly maximum demands less than 20 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-32TOU S
SMALL GENERAL SERVICE (21 kW - 100 kW)
TIME OF USE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 20 kW and less than or equal to 100 kW per month.

The Company will place the Customer on the applicable Rate Schedule E-32TOU XS, E-32TOU S, E-32TOU M, or E-32TOU L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination. The Company may also place the Customer on the Applicable Rate Schedule during the year, if the Customer has experienced a significant and permanent change in load as determined by the Company. Such placement will be based on available information.

Customers will be billed on Schedule E-32 S or E-32 XS depending on the On-peak Monthly Maximum Demand for each billing cycle.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt/kilowatt-hour meter.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

Service under this schedule is generally provided at secondary voltage or primary voltage when the customer owns the distribution transformer(s).

RATES

The bill shall be computed at the following rates, plus any adjustments incorporated in this rate schedule:

Basic Service Charge:

For service through Self-Contained Meters:	$ 0.658	per day, or
For service through Instrument-Rated Meters:	$ 1.328	per day, or
For service at Primary Voltage:	$ 3.477	per day

RATES (cont)

Bundled Standard Offer Service

Demand Charge:

Secondary Service:	$ 13.230	per kW for the first 100 On-Peak kW, plus
	$ 8.455	per kW for all additional On-Peak kW, plus
	$ 5.705	per kW for the first 100 Off-Peak kW, plus
	$ 3.178	per kW for all additional Off-Peak kW
Primary Service:	$ 12.753	per kW for the first 100 On-Peak kW, plus
	$ 8.384	per kW for all additional On-Peak kW, plus
	$ 5.107	per kW for the first 100 Off-Peak kW, plus
	$ 3.095	per kW for all additional Off-Peak kW

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 0.07352 per kWh during On-Peak hours, plus $ 0.05833 per kWh during Off-Peak hours	$ 0.05622 per kWh during On-Peak hours, plus $ 0.04102 per kWh during Off-Peak hours

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.129	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.414	per day, or
Instrument-Rated Meters:	$ 1.084	per day, or
Primary:	$ 3.233	per day

These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

Meter Reading:	$ 0.038	per day
Billing:	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh

RATES (cont)

Unbundled Standard Offer Service (cont)

Delivery Charge:

Secondary Service:	$ 6.008	per kW for the first 100 On-Peak kW, plus
	$ 1.233	per kW for all additional On-Peak kW, plus
	$ 2.956	per kW for the first 100 Off-Peak kW, plus
	$ 0.429	per kW for all additional Off-Peak kW, plus
Primary Service:	$ 5.531	per kW for the first 100 On-Peak kW, plus
	$ 1.162	per kW for all additional On-Peak kW, plus
	$ 2.358	per kW for the first 100 Off-Peak kW, plus
	$ 0.346	per kW for all additional Off-Peak kW, plus

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 7.222 per On-Peak kW, plus $ 2.749 per Off-Peak kW, plus $ 0.07187 per kWh during On-Peak hours, plus $ 0.05668 per kWh during Off-Peak hours	$ 7.222 per On-Peak kW, plus $ 2.749 per Off-Peak kW, plus $ 0.05457 per kWh during On-Peak hours, plus $ 0.03937 per kWh during Off-Peak hours

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company
may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

POWER FACTOR (cont)

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the On-Peak and Off-Peak periods during the billing period, as determined from readings of the Company's meter.

Monthly Maximum Demand will be based on the highest average kW supplied during the 15-minute period during either the On-Peak or Off-Peak hours of the billing period, as determined from readings of the Company's meter.

On-peak Monthly Maximum Demand will be based on the highest average kW supplied during the 15-minute period during the On-peak hours of the billing period, as determined from readings of the Company's meter.

The Average Monthly Maximum Demand shall equal the average of the On-peak Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the On-peak Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum On-peak kW provided by the Customer and approved by the Company.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

On-Peak hours:	11:00 am – 9:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

ADJUSTMENTS (cont)

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

For customers with monthly maximum demands greater than 20 and less than 100 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-32TOU M
MEDIUM GENERAL SERVICE (101 kW – 400 kW)
TIME OF USE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 100 kW and less than or equal to 400 kW per month.

The Company will place the Customer on the applicable Rate Schedule E-32TOU XS, E-32TOU S, E-32TOU M, or E-32TOU L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination. The Company may also place the Customer on the Applicable Rate Schedule during the year, if the Customer has experienced a significant and permanent change in load as determined by the Company. Such placement will be based on available information.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt/kilowatt-hour meter.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service nor to service for which Rate Schedule E-35 is applicable.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

Service under this schedule is generally provided at secondary voltage; primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 0.658	per day, or
For service through Instrument-Rated Meters:	$ 1.328	per day, or
For service at Primary Voltage:	$ 3.477	per day, or
For service at Transmission Voltage:	$ 26.855	per day

RATES (cont)

Bundled Standard Offer Service (cont)

Demand Charge:

Secondary Service:	$ 13.343	per kW for the first 100 On-Peak kW, plus
	$ 8.523	per kW for all additional On-Peak kW, plus
	$ 5.759	per kW for the first 100 Off-Peak kW, plus
	$ 3.206	per kW for all additional Off-Peak kW
Primary Service:	$ 12.861	per kW for the first 100 On-Peak kW, plus
	$ 8.451	per kW for all additional On-Peak kW, plus
	$ 5.154	per kW for the first 100 Off-Peak kW, plus
	$ 3.123	per kW for all additional Off-Peak kW
Transmission Service:	$ 12.000	per kW for the first 100 On-Peak kW, plus
	$ 8.154	per kW for all additional On-Peak kW, plus
	$ 4.472	per kW for the first 100 Off-Peak kW, plus
	$ 3.011	per kW for all additional Off-Peak kW

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 0.07299 per kWh during On-Peak hours, plus $ 0.05790 per kWh during Off-Peak hours	$ 0.05581 per kWh during On-Peak hours, plus $ 0.04073 per kWh during Off-Peak hours

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.129	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.414	per day, or
Instrument-Rated Meters:	$ 1.084	per day, or
Primary:	$ 3.233	per day, or
Transmission:	$ 26.611	per day

These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

RATES (cont)

Unbundled Standard Offer Service (cont)

Revenue Cycle Service Charges (cont)

Meter Reading:	$ 0.038	per day
Billing:	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh

Delivery Charge:

Secondary Service:	$ 6.052	per kW for the first 100 On-Peak kW, plus
	$ 1.232	per kW for all additional On-Peak kW, plus
	$ 2.985	per kW for the first 100 Off-Peak kW, plus
	$ 0.432	per kW for all additional Off-Peak kW
Primary Service:	$ 5.570	per kW for the first 100 On-Peak kW, plus
	$ 1.160	per kW for all additional On-Peak kW, plus
	$ 2.380	per kW for the first 100 Off-Peak kW, plus
	$ 0.349	per kW for all additional Off-Peak kW
Transmission Service:	$ 4.709	per kW for the first 100 On-Peak kW, plus
	$ 0.863	per kW for all additional On-Peak kW, plus
	$ 1.698	per kW for the first 100 Off-Peak kW, plus
	$ 0.237	per kW for all additional Off-Peak kW

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 7.291 per On-Peak kW, plus $ 2.774 per Off-Peak kW, plus $ 0.07134 per kWh during On-Peak hours, plus $ 0.05625 per kWh during Off-Peak hours	$ 7.291 per On-Peak kW, plus $ 2.774 per Off-Peak kW, plus $ 0.05416 per kWh during On-Peak hours, plus $ 0.03908 per kWh during Off-Peak hours

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company
may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the On-Peak and Off-Peak periods during the billing period, as determined from readings of the Company's meter.

Monthly Maximum Demand will be based on the highest average kW supplied during the 15-minute period during either the On-Peak or Off-Peak hours of the billing period, as determined from readings of the Company's meter.

On-peak Monthly Maximum Demand will be based on the highest average kW supplied during the 15-minute period during the On-peak hours of the billing period, as determined from readings of the Company's meter.

The Average Monthly Maximum Demand shall equal the average of the On-peak Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the On-peak Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum On-peak kW provided by the Customer and approved by the Company.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

On-Peak hours:	11:00 am – 9:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1 The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2 The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

3 The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

For customers with monthly maximum demands greater than 100 and less than 400 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 400 kW per month.

The Company will place the Customer on the applicable Rate Schedule E-32TOU XS, E-32TOU S, E-32TOU M, or E-32TOU L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination. The Company may also place the Customer on the Applicable Rate Schedule during the year, if the Customer has experienced a significant and permanent change in load as determined by the Company. Such placement will be based on available information.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

This rate schedule is applicable to all Standard Offer and Direct Access electric service required when such service is supplied at one point of delivery and measured through one meter. Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt/kilowatt-hour meter.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service nor to service for which Rate Schedule E-35 is applicable.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

Service under this schedule is generally provided at secondary voltage; primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 0.658	per day, or
For service through Instrument-Rated Meters:	$ 1.328	per day, or

RATES (cont)

Bundled Standard Offer Service (cont)

For service at Primary Voltage:	$ 3.477	per day, or
For service at Transmission Voltage:	$ 26.855	per day

Demand Charge:

Secondary Service:	$ 13.139	per kW for the first 100 On-Peak kW, plus
	$ 8.379	per kW for all additional On-Peak kW, plus
	$ 5.688	per kW for the first 100 Off-Peak kW, plus
	$ 3.168	per kW for all additional Off-Peak kW
Primary Service:	$ 12.663	per kW for the first 100 On-Peak kW, plus
	$ 8.308	per kW for all additional On-Peak kW, plus
	$ 5.090	per kW for the first 100 Off-Peak kW, plus
	$ 3.085	per kW for all additional Off-Peak kW
Transmission Service:	$ 11.813	per kW for the first 100 On-Peak kW, plus
	$ 7.282	per kW for all additional On-Peak kW, plus
	$ 4.417	per kW for the first 100 Off-Peak kW, plus
	$ 2.974	per kW for all additional Off-Peak kW

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 0.07184 per kWh during On-Peak hours, plus $ 0.05699 per kWh during Off-Peak hours	$ 0.05492 per kWh during On-Peak hours, plus $ 0.04007 per kWh during Off-Peak hours

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.129	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.414	per day, or
Instrument-Rated Meters:	$ 1.084	per day, or
Primary:	$ 3.233	per day, or
Transmission:	$ 26.611	per day

These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

RATES (cont)

Unbundled Standard Offer Service (cont)

Revenue Cycle Service Charges (cont)

Meter Reading:	$ 0.038	per day
Billing:	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh

Delivery Charge:

Secondary Service:	$ 5.939	per kW for the first 100 On-Peak kW, plus
	$ 1.179	per kW for all additional On-Peak kW, plus
	$ 2.948	per kW for the first 100 Off-Peak kW, plus
	$ 0.428	per kW for all additional Off-Peak kW
Primary Service:	$ 5.463	per kW for the first 100 On-Peak kW, plus
	$ 1.108	per kW for all additional On-Peak kW, plus
	$ 2.350	per kW for the first 100 Off-Peak kW, plus
	$ 0.345	per kW for all additional Off-Peak kW
Transmission Service:	$ 4.613	per kW for the first 100 On-Peak kW, plus
	$ 0.082	per kW for all additional On-Peak kW, plus
	$ 1.677	per kW for the first 100 Off-Peak kW, plus
	$ 0.234	per kW for all additional Off-Peak kW

Generation Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 7.200 per On-Peak kW, plus $ 2.740 per Off-Peak kW, plus $ 0.07019 per kWh during On-Peak hours, plus $ 0.05534 per kWh during Off-Peak hours	$ 7.200 per On-Peak kW, plus $ 2.740 per Off-Peak kW, plus $ 0.05327 per kWh during On-Peak hours, plus $ 0.03842 per kWh during Off-Peak hours

DIRECT ACCESS

The bill for Direct Access customers under this rate schedule will consist of the applicable Unbundled Components Basic Service Charge, System Benefits Charge, and Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company
may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the On-Peak and Off-Peak periods during the billing period, as determined from readings of the Company's meter.

Monthly Maximum Demand will be based on the highest average kW supplied during the 15-minute period during either the On-Peak or Off-Peak hours of the billing period, as determined from readings of the Company's meter.

On-peak Monthly Maximum Demand will be based on the highest average kW supplied during the 15-minute period during the On-peak hours of the billing period, as determined from readings of the Company's meter.

The Average Monthly Maximum Demand shall equal the average of the On-peak Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the On-peak Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum On-peak kW provided by the Customer and approved by the Company.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

On-Peak hours:	11:00 am – 9:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1 The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2 The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

3 The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

For customers with monthly maximum demands greater than 400 kW, any applicable contract period will be set forth in the Company's standard agreement for service. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer or, if no additional distribution construction is required, the contract period will be one (1) year or longer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-34
EXTRA LARGE GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose monthly maximum demand registers 3,000 kW or more for three (3) consecutive months in any continuous twelve (12) month period ending with the current month. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be three phase, 60 Hertz, at the Company's standard voltages that are available within the vicinity of the customer site.

Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 0.658	per day, or
For service through Instrument-Rated Meters:	$ 1.328	per day, or
For service at Primary Voltage:	$ 3.477	per day, or
For service at Transmission Voltage:	$ 26.855	per day

Demand Charge:

Secondary Service:	$ 16.646	per kW, or
Primary Service:	$ 15.687	per kW, or
Transmission Service:	$ 10.914	per kW

The Demand Charge for military base customers taking primary service and served from dedicated distribution feeder(s) shall be reduced to $11.749 per kW.

Energy Charge:	$ 0.04258	per kWh

RATES (cont)

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service:

Basic Service Charge:	$ 0.129	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.414	per day, or
Instrument-Rated Meters:	$ 1.084	per day, or
Primary:	$ 3.233	per day, or
Transmission:	$ 26.611	per day

These daily metering charges apply to typical installations. Customers requiring specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

Meter Reading:	$ 0.038	per day
Billing:	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh
Delivery Charge:		
Secondary Service:	$ 6.012	per kW
Primary Service:	$ 5.053	per kW
Transmission Service:	$ 0.280	per kW

The Delivery Charge for military base customers taking primary service and served from a dedicated distribution feeder(s) Company substation shall be reduced to $1.115 per kW.

Generation Charge:	$ 10.634	per kW, plus
	$ 0.04093	per kWh

Direct Access

The bill for Direct Access customers will consist of the applicable Unbundled Components Basic Service Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

MINIMUM

The bill for service under this rate schedule shall not be less than the applicable Bundled Standard Offer Service Basic Service Charge plus the applicable Bundled Standard Offer Service Demand Charge for each kW as determined below.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a non-conforming power factor or other detrimental conditions shall be required to remedy problems or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be the greater of the following:

1. The average kW supplied during the 15-minute period (or other period as specified by an individual customer contract) of maximum use during the month, as determined from readings of the Company's meter.

2. 80% of the highest kW measured during the six (6) summer billing months (May-October) of the twelve (12) months ending with the current month.

3. The minimum kW specified in the agreement for service or individual contract.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

ADJUSTMENTS (cont)

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

The contract period for customers served under this rate schedule will be three (3) years, at the Company's option. If the Company determines that the customer service location is such that unusual or substantial distribution construction is required to serve the site, the Company may require a contract of ten (10) years or longer with a standard seven (7) year termination provision.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-35
EXTRA LARGE GENERAL SERVICE
TIME OF USE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose monthly maximum demand registers 3,000 kW or more for three (3) consecutive months in any continuous twelve (12) month period ending with the current month. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be three phase, 60 Hertz, at the Company's standard voltages that are available within the vicinity of the customer site.

Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 0.658	per day, or
For service through Instrument-Rated Meters:	$ 1.328	per day, or
For service at Primary Voltage:	$ 3.477	per day, or
For service at Transmission Voltage:	$ 26.855	per day

Demand Charge:

Secondary Service:	$ 14.351	per On-Peak kW, plus
	$ 2.945	per Off-Peak kW, or
Primary Service:	$ 13.545	per On-Peak kW, plus
	$ 2.864	per Off-Peak kW, or
Transmission Service:	$ 9.385	per On-Peak kW, plus
	$ 2.448	per Off-Peak kW

The Demand Charge for military base customers taking primary service and served from dedicated distribution feeder(s) shall be reduced to $ 10.502 per On-Peak kW and $ 2.559 per Off-Peak kW.

RATES (cont)

Energy Charge:	$ 0.04749	per kWh during On-Peak hours, plus
	$ 0.03559	per kWh during Off-Peak hours

Bundled Standard Offer Service consists of the following Unbundled Components:

Unbundled Standard Offer Service

Basic Service Charge:	$ 0.129	per day
Revenue Cycle Service Charges:		
Metering:		
Self-Contained Meters:	$ 0.414	per day, or
Instrument-Rated Meters:	$ 1.084	per day, or
Primary:	$ 3.233	per day, or
Transmission:	$ 26.611	per day

These daily metering charges apply to typical installations. Customers requiring specialized facilities are subject to additional metering charges that reflect the additional cost of the installation, (for example, a customer taking service at 230 kV). Adjustments to unbundled metering components will result in an adjustment to the bundled Basic Service Charge.

Meter Reading:	$ 0.038	per day
Billing:	$ 0.077	per day
System Benefits Charge:	$ 0.00165	per kWh
Delivery Charge:		
Secondary Service:	$ 5.336	per On-Peak kW, plus
	$ 0.534	per kW Off-Peak, or
Primary Service:	$ 4.530	per On-Peak kW, plus
	$ 0.453	per Off-Peak kW, or
Transmission Service:	$ 0.370	per On-Peak kW, plus
	$ 0.037	per Off-Peak kW

In addition, the Delivery Charge for military base customers taking primary service and served directly from a Company substation shall be reduced to $ 1.487 per On-Peak kW and $ 0.148 per Off-Peak kW.

Generation Charge:	$ 9.015	per On-Peak kW, plus
	$ 2.411	per Off-Peak kW, plus
	$ 0.04584	per kWh during On-Peak hours, plus
	$ 0.03394	per kWh during Off-Peak hours

DIRECT ACCESS

The bill for Direct Access customers will consist of the applicable Unbundled Components Basic Service Charge, the System Benefits Charge, and the Delivery Charge, plus any applicable adjustments incorporated in this schedule. Direct Access customers must acquire and pay for generation, transmission, and revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, the applicable Unbundled Components Revenue Cycle Service Charges will be applied to the customer's bill.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

MINIMUM

The bill for service under this rate schedule shall not be less than the applicable Bundled Standard Offer Service Basic Service Charge plus the applicable Bundled Standard Offer Service Demand Charge for the minimum kW specified in the agreement for service or individual customer contract.

DETERMINATION OF KW

For billing purposes, the On-Peak kW used in this rate schedule shall be the greater of the following:

1. The average On-Peak kW supplied during the 15-minute period (or other period as specified by an individual customer contract) of maximum use during the On-Peak hours of the month, as determined from readings of the Company's meter.

2. 80% of the highest On-Peak kW measured during the six (6) summer billing months (May-October) of the twelve (12) months ending with the current month.

The Off-Peak kW used in this rate schedule shall be the average kW supplied during the 15-minute period (or other period as specified by individual customer contract) of maximum use during the Off-Peak hours of the month as determined from readings of the Company's meter.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

On-Peak hours:	11:00 am – 9:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

TIME PERIODS (Cont)

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

The contract period for customers served under this rate schedule will be three (3) years, at the Company's option. If the Company determines that the customer service location is such that unusual or substantial distribution construction is required to serve the site, the Company may require a contract of ten (10) years or longer with a standard seven (7) year termination provision.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-53
GENERAL SERVICE
ATHLETIC STADIUMS AND SPORTS FIELDS

THIS RATE IS CANCELED EFFECTIVE XXXXX PER A.C.C. DECISION NO. XXXXX.

RATE SCHEDULE E-54
GENERAL SERVICE
SEASONAL SERVICE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to Standard Offer or Direct Access electric service billed under general service rate schedules (except as limited below) where the customer's requirements are distinctly of a recurring seasonal nature, and where the customer enters into an agreement for service with the Company for a sufficient period of time and guarantees payments of a sufficient amount (in no event less than the MINIMUM 12-MONTH CHARGE in any 12 consecutive months) to justify the Company's expenses for installing service facilities and leaving them in place from season to season.

The application of this rate schedule is subject to the following limitations:

1. This schedule is applicable only to electric service otherwise eligible for Rate Schedule E-32 L.

2. Customers whose highest measured monthly kW for the calendar year occurs in the billing months of June, July or August are not eligible for this rate schedule.

RATES

Customers being served under this rate schedule will be billed in accordance with Rate Schedule E-32 L with the following exception:

The minimum bill shall be the minimum specified in the otherwise applicable rate schedule, but not more than an amount sufficient to make the total charges for the 12 months ending with the current month equal to twelve times the minimum specified in the rate schedule as calculated on the highest kW established during the 12 months ending with the current month, or the minimum kW specified in an agreement for service, whichever is greater, but in no event less than the MINIMUM 12-MONTH CHARGE.

MINIMUM 12-MONTH CHARGE: $ 603.49

RATE RIDER SCHEDULE CPP-GS
CRITICAL PEAK PRICING – GENERAL SERVICE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

The Rate Schedule CPP-GS is available to retail Standard Offer customers served on Rate Schedules E-32 M, E-32 L, E-32TOU M, E-32TOU L, E-34, E-35, and E-221. The eligible customer must demonstrate the ability to reduce usage during Critical Events by a minimum of 200 kW and submit a load reduction plan, which must be approved by the Company prior to participation. The eligible customer must also have interval metering.

All provisions of the customer's otherwise applicable rate schedule will apply in addition to the charges in Schedule CPP-GS. Schedule CPP-GS is available for a period of two years from the initial availability.

A customer may not simultaneously participate in Schedule CPP-GS and another demand response rate or program. A customer may participate in Schedule CPP-GS and a net metering rate schedule, subject to meter availability. However, any customer generation in excess of load during a CPP Event will be netted according to the customer's otherwise applicable rate schedule and will not be netted against usage during a subsequent CPP Event.

RATES

A. Critical Peak Price $ 0.250000 per kWh
Critical Peak Price applies to kWh usage during a CPP Event.

B. Energy Discount

Rate Schedule E-32 M	$ (0.010351)	per kWh
Rate Schedule E-32 L	$ (0.009533)	per kWh
Rate Schedule E-32 TOU M	$ (0.009266)	per kWh
Rate Schedule E-32 TOU L	$ (0.008680)	per kWh
Rate Schedule E-34	$ (0.008519)	per kWh
Rate Schedule E-35	$ (0.007396)	per kWh
Rate Schedule E-221	$ (0.006116)	per kWh

Energy Discount applies to Customer's total monthly kWh during June through September billing cycles.

CONDITIONS

A. CPP Events: CPP Events may be invoked by the Company for the period 2 p.m. to 7 p.m., weekdays (Monday through Friday) during June through September. Holidays are excluded, which include Independence Day (July 4th) and Labor Day (first Monday in September). A CPP Event can be triggered by severe weather, high load, high wholesale prices, or a major generation or transmission outage, as determined by the Company.

B. Number and Duration of CPP Events: The Company will invoke a minimum of 6 CPP Events and up to a maximum of 18 CPP Events per calendar year, for 5 hours per event and a maximum of 90 hours per year.

C. CPP Event Notification/Communication: Customers shall be notified of a CPP Event in advance by 4:00 PM the day prior through a phone message, e-mail, or text message. Receipt of such notice is the responsibility of the participating customer.

D. CPP Event Cancellation: Once a CPP event alert has been initiated, there are no conditions that would warrant the critical event to be cancelled.

RATE RIDER IRR
EXTRA LARGE GENERAL SERVICE
INTERRUPTIBLE RIDER

AVAILABILITY

This rate schedule is available in territory served by the Company and at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served. Customers located in Metro Phoenix and City of Yuma service areas where the Peak Solutions Program is available are not eligible for this rate until January 1, 2015.

APPLICATION

This rate schedule is applicable to retail Standard Offer customers served on Schedules E-34 and E-35. All provisions of the customer's applicable retail rate schedule shall continue to apply in addition to the provisions of Schedule IRR.

Customer cannot participate in Schedule IRR in conjunction with other demand response programs and rates such as Peak Event Pricing (CPP-GS), Peak Solutions, Power Partners, and other demand response programs and rates that may be offered from time to time.

Participation under this schedule is subject to: the availability of required metering and communication equipment compatible with the customer's applicable retail rate schedule and electrical service configuration; completion of the necessary enhancements to the Company's billing system; and availability of the necessary load data to establish the Baseline Load.

DEFINITIONS

Program Year – The calendar year in which the customer is subject to, and compensated for, an Event.

Event - A request by APS for customers to interrupt their load due to high loads, system emergencies, and high wholesale capacity or energy prices, as determined by the Company.

Firm Service Level -The level of demand (kW) to which the customer agrees to reduce their load for each hour of an Event, as specified in the Interruptible Contract.

Baseline Load – The hourly load (kW) during an Event that would have occurred without the interruption.

Actual Interrupted Demand – The average kW that the customer reduces during all event hours in the Program Year.

Required Interrupted Demand – The average kW that the customer is obligated to reduce during all event hours in the program year.

Shortfall Demand – The average kW that the customer fails to reduce to the Firm Service Level during all event hours in the Program Year.

Actual Interrupted Energy – The energy (kWh) that the customer reduces during all event hours in the Program Year.

LOAD INTERRUPTION

Events can be called by APS due to high loads, system emergencies, and high wholesale capacity or energy prices. When APS notifies the customer of an Event, the customer shall reduce their load to the Firm Service Level for each hour of the Event. The customer is responsible for reducing load and shall not use back-up generation to achieve the required load reduction.

CUSTOMER ENROLLMENT AND CONFIRMATION

Customer enrollment shall occur during the open enrollment period, which is October 1 through December 31 prior to the next Program Year. For the first year of the program, enrollment may occur up to April 1 of the Program Year, if necessary, due to timing of initial approval of the Schedule IRR by the Arizona Corporation Commission.

During enrollment, customer shall choose program options, set the Firm Service Level, demonstrate the ability to curtail load by at least 500 kW, and execute an Interruptible Contract.

Each year during the open enrollment period the customer may reset their Firm Service Level, change program options, or discontinue participation in the schedule.

Customer may reset the Firm Service Level by April 1 of the Program Year, if necessary, due to a significant change in their expected load or business situation.

INTERRUPTIBLE HOURS AND OPTIONS

Events shall occur June through September, all days of the week including Holidays, from 12 noon to 8 p.m.

Customer shall choose the maximum number of Events and hours per Event per Program Year from the following choices:

Option	Max Hours per Event	Max Number of Events	Max Interruptible Hours
1	4	20	80
2	8	10	80

APS shall not call more than one interruption event per day. APS shall call at least 2 events per year.

EVENT NOTIFICATION

APS shall notify customer of an Event by email, cell phone, land line, text message or pager. Customer shall choose either a 30-minute or 2-hour notice. Customer is responsible for receiving notification and shall acknowledge receipt of notification to APS within 15 minutes.

BILLING DETERMINANTS

Baseline Load shall be calculated using hourly metered load (kW) data for the highest three load days out of the previous ten non-Event days and metered load data for the hours just prior to the interruption, as calculated by APS. The highest three load days shall be determined from the average kW for the Event hours. The Baseline Load shall not be less than the actual metered load or the Firm Service Level for any Event hour.

BILLING DETERMINANTS (cont)

Required Interrupted Demand shall be derived by subtracting the Firm Service Level (kW) from the Baseline Load (kW) for each Event hour and then averaged over all event hours for the Program Year.

Actual Interrupted Demand shall be derived by subtracting the metered load (kW) from the Baseline Load (kW) for each Event hour and then averaged over all Event hours for the Program Year. Load reductions below the Firm Service Level shall not be included in this calculation.

Shortfall Demand shall be derived by subtracting the Actual Interrupted Demand from the Required Interrupted Demand. This amount shall not be less than zero.

Actual Interrupted Energy shall be equal to the Actual Interrupted Demand multiplied by the total event hours during the Program Year.

All billing determinants shall be rounded to the nearest whole unit.

CREDITS

The customer shall receive a capacity and energy credit for reducing hourly usage during all event hours. The capacity credit shall be derived by multiplying the Actual Interrupted Demand by the applicable capacity credit rate. The energy credit shall be derived by multiplying the Actual Interrupted Energy by the applicable energy credit rate.

The credits shall be issued once a year in November billing cycles through a direct payment or a bill credit, at APS's option.

The credit rates shall be revised from time to time, as approved by the Arizona Corporation Commission, but shall not change during the Program Year.

All customers participating in a five-year agreement will be subject to the revised credit rates for the Program Year, regardless of the number of years remaining on their contract.

1 Year Agreement Credit Rate:

	30 Minute Notice		2-Hour Notice	
Option	Capacity $/kW-Yr	Energy $/kWh	Capacity $/kW-Yr	Energy $/kWh
1	$7.975	$0.09969	$7.178	$0.08972
2	$5.995	$0.07493	$5.395	$0.06745

5 Year Agreement Credit Rate:

	30 Minute Notice		2-Hour Notice	
Option	Capacity $/kW-Yr	Energy $/kWh	Capacity $/kW-Yr	Energy $/kWh
1	$9.882	$0.12353	$8.894	$0.11117
2	$7.428	$0.09285	$6.685	$0.08356

PENALTIES

For any Event Year, if the Average Shortfall Demand is greater than 5% and less than or equal to 10% of the Required Interrupted Demand, the customer will receive 50% of their capacity credit. If the Average Shortfall Demand exceeds 10% of the Required Interrupted Demand, the customer will not receive a capacity credit. In either case, the customer will continue to receive 100% of their energy credit. The penalty shall not apply to the first Event of the customer's first Program Year on Schedule IRR.

If the customer terminates participation prior to the contract term in a five-year agreement, they shall pay the Company a penalty equal to the relevant Capacity Credit rate times the Required Interrupted Demand from the most recent Event Year (with a minimum of 500 kW) times the number of years remaining on the agreement. The total penalty shall be assessed at the time of termination.

In addition, if a customer terminates participation prior to the contract term in a one-year or a five-year agreement, they shall not be allowed to participate in the rate for the two subsequent years.

ESTIMATION OF MISSING DATA

If at least 50% of the hourly metered load data is available for an Event, any missing hourly kW values shall be estimated by the average of the available hourly data for that Event. If less than 50% is available, the missing hourly kW values will be estimated at the Firm Service Level.

METERING

Customer shall be served with interval metering equipment necessary to record and communicate hourly (or partial hour) load data. APS shall provide and install the metering and communication equipment at no additional cost to the customer and shall pay any ongoing cell phone or other communication costs, if applicable.

TERMS AND CONDITIONS

Service under this rate schedule is subject to APS's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, which contains provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a service agreement.

RATE RIDER SCHEDULE PPR
PREFERENCE POWER RIDER

APPLICATION

This Rate Schedule PPR Preference Power Rider ("Schedule PPR") is applicable to all Standard Offer customers ("Customer") who receive a Firm Electric Service allocation of preference power ("Preference Power") from the Western Area Power Administration ("WAPA"), an agency of the U.S. Department of Energy. All provisions of Customer's current applicable rate schedule will apply in addition to this Schedule PPR. Schedule PPR may be used in conjunction with all non-residential rate schedules that have unbundled charges.

Schedule PPR is applicable to new Preference Power allocations received from WAPA after January 1, 2007. Customer must enter into an "Electrical Supply Agreement" for "Customers with Preference Power" ("Agreement") with the Company prior to receiving service under Schedule PPR.

DETERMINATION OF GENERATION NET POWER

The Company will provide delivery and transmission services for Customer's Total Power, and will provide generation services for the Customer's Net Power, according to the following definitions:

1. Total Power equals Customer's demand ("Total Demand") and energy ("Total Energy") for the billing period, as metered by the Company.

2. Preference Power equals the demand ("Preference Demand") and energy ("Preference Energy") from Customer's Firm Electric Service allocation for the billing period, as scheduled by the Company. Preference Power will be reduced for electrical losses as specified in the Agreement.

3. Net Power equals Total Power less Preference Power. Net Demand equals Total Demand less Preference Demand. Net Energy equals Total Energy less Preference Energy for the billing period. If Total Power is less than Preference Power for a billing period, then Net Power shall equal zero for the billing period.

RATES

Service under this rate schedule shall be billed according to Customer's current applicable rate schedule, except as follows:

1. The eligibility for placement on a rate schedule will be determined by Total Demand.

2. The unbundled generation kWh charges in Customer's current applicable rate schedule will be applied to the Net Energy used.

3. The determination of billing kW for generation services shall be based on Net Demand computed in accordance with the provisions of Customer's current applicable rate schedule. The determination of billing kW for transmission and delivery services shall be based on Total Demand computed in accordance with the provisions of Customer's current applicable rate schedule.

4. The kWh charges under Adjustment Schedule PSA-1 and Adjustment Schedule EIS will be applied to the Net Energy determination.

5. All other kWh and kW charges in Customer's current applicable rate schedule and any other applicable adjustment schedules will be applied to the Total Energy or Total Demand, as applicable.

EXPERIMENTAL RATE RIDER SCHEDULE AG-1
ALTERNATIVE GENERATION
GENERAL SERVICE

AVAILABILITY

This experimental rate rider schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate rider schedule is available for all Standard Offer customers who have an aggregated Peak load of 10 MW or more each month throughout the year, as measured at the customer's meter(s). All provisions of customer's current applicable rate schedule(s) will apply in addition to this Schedule AG-1, except as noted herein. This experimental rate schedule shall be available for three years after approval by the Arizona Corporation Commission. Total program participation shall be limited to 200 MW of peak load, on a first come first served basis.

DEFINITION

Generation Service Provider: A third party from which the customer contracts to provide power for their load.

DESCRIPTION OF SERVICES

The Generation Service Provider shall provide the customer firm power sufficient to meet their full requirements (total load), as agreed to by the customer and the Company.

The customer shall obtain a Generation Service Provider and notify the Company. The Company will subsequently contract with the Generation Service Provider on behalf of the customer for the specified power and manage the contract for the customer.

The Company shall provide transmission delivery and network services to the customer in accordance with normal retail electric service.

The Customer will be responsible for paying the cost of the energy from the Generation Service Provider for the Generation Service specified in the contract.

Other than the unbundled generation component, all kWh and kW charges in Customer's current applicable parent rate schedule and any other applicable adjustment schedules will be applied to the Energy or Demand, as applicable. Eligibility for placement on a rate schedule will be determined by Customer's Demand, in accordance with the Customer's parent Rate Schedule.

DELIVERY OF POWER TO APS' SYSTEM

Power provided from the Generation Service Provider must be firm power (Western System Power Pool Schedule C or equivalent) and must be contracted in advance and delivered to the Company at APS network delivery points that are not limited by APS' capability to deliver contracted quantities. If the Generation Services do not cover hourly loads in any given hour, the Company will supply for each hour, and the customer will pay for, necessary generation at the hourly pricing proxy plus $4/MWh for up to 10% of the hourly deficit and an additional hourly charge of $6/MWh for hourly supply deficit over 10%. If the Generation Services supplies more power than needed in any given hour, the Company will credit the customer for the excess power for each hour at the hourly pricing proxy minus $4/MWh for up to 10% of the excess and an additional deduction of $6/MWh for the hourly excess over 10%.

DETERMINATION OF HOURLY PRICING PROXY

Hourly pricing proxy shall be the published Dow Jones Electricity Palo Verde Hourly Index for the power delivery date. Hourly prices are expressed in $ per MWh.

RESERVE CAPACITY CHARGE

Customer will pay company a monthly reserve capacity charge equal to 15% of customer's monthly peak load.

POWER SUPPLY ADJUSTER AND HEDGE COST TRUE-UP

When taking this service, the customer will be subject to a true up mechanism (either plus or minus) to account for the unpaid or overpaid Power Supply Adjuster balance and hedge cost associated with the Customers Standard Offer Service.

DEFAULT OF THE THIRD PARTY GENERATION PROVIDER

In the event that the Generation Service Provider is unable to meet its contractual obligations, the customer must notify the Company, and enter into another power contract within 60 days. Prior to execution of a new power contract, the Company shall proved generation service to the Customer, which will be charged at the hourly pricing proxy for generation service.

If the customer is unable to secure a new generation contract in that sixty day period, they will be deemed a returning customer, subject to conditions below.

RETURN TO COMPANY'S BUNDLED GENERATION SERVICE

If the Customer returns to the Company's bundled Generation Service, the Customer will be charged a Returning Customer Charge. The charge will be identified in the Electric Service Agreement between the Customer and the Company and will be in addition to the Standard Offer service charges. The Returning Customer Charge will be based on the cost differential between the applicable Standard Offer rate generation component and the cost of the resources required to serve the returning customer(s). The costs associated with serving customers that are required to enter into Returning Customer Charge agreements will be kept separate from the retail power supply costs subject to recovery through the Power Supply Adjustment. The types of costs that will be used to develop the Returning Customer Charge are incremental Power Supply, Transmission, Ancillary Services and Metering. These costs will be amortized over an appropriate period to allow their timely recovery. In no event, however, will the Returning Customer Charge be in place less than one year, or last longer than 36 months and in no case shall be less than zero for any individual customer.

When taking this service, the Customer will be subject to a true up mechanism (either plus or minus) to account for the unpaid or overpaid Power Supply Adjuster balance and related hedge cost associated with the Customers Standard Offer Service.

RATES

Service under this rate schedule shall be billed according to Customer's current applicable parent rate schedule, except as follows:

1. The adjustment schedules PSA, ERA-1 and EIS will not apply to the Customer's bill while said Customer is on Rate Schedule AG-1.
2. In addition, the Customer agrees to pay a Management fee of $0.00060 per kWh.
3. Other than the unbundled Generation component, all kWh and kW charges in Customer's current applicable parent rate schedule and any other applicable adjustment schedules will be applied to the Energy or Demand, as applicable.

CONTRACT TERM AND REQUIREMENTS

The term of the Customer's contract with the Generation Service Provider shall be for not less than one year, and shall not exceed three years.

The Customer will enter a contract with the Company, stating the pertinent details of the transaction with the Generation Service Provider, including but not limited to the scheduling of power, location of delivery and other terms related APS' management of the generation resource.

CREDIT REQUIREMENTS

Customer must provide all collateral and margining requirements defined in the Generation Service contract to the Company. Failure to do so will be considered a default by the Customer and result in a return to bundled services under the terms stated in the return to Company's bundled service above. In addition, Company will be paid by the Customer for any losses associated with terminating the contract with the Generation Service Provider.

All Generation Service Providers must have at least an investment grade credit rating and demonstrate creditworthiness acceptable to Company.

ADJUSTMENTS

All adjustments of the Customers parent Rate Schedule will apply to the Customers bill, including 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 APS 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.

Classified

RATE SCHEDULE E-20
CLASSIFIED SERVICE
TIME OF USE
FOR RELIGIOUS HOUSES OF WORSHIP

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to Standard Offer electric service for non-taxable religious houses of worship whose main purpose is worship and who have an established and continuing membership. Only the meter that measures service to the building in which the sanctuary or principal place of worship is located is eligible for this schedule. Customers must apply to the Company in order to determine eligibility for service under this schedule, and the Company may request a copy of the Internal Revenue Service letter in which the customer's non-taxable status as a religious organization is determined. In addition, customers agree to provide the Company a copy of any Internal Revenue Service letter which changes or supersedes that tax status determination.

Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, and this rate schedule will become effective only after the Company has installed the required timed kilowatt meter.

Additionally, this rate schedule is applicable only to those customers being served on the Company's Rate Schedule E-20 prior to January 1, 2011.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service nor to service for which Rate Schedules E-34 or E-35 is applicable. Direct Access customers are not eligible for this rate schedule.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this schedule:

Basic Service Charge: $ 1.147 per day

Demand Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$1.29 per On-Peak kW	$1.29 per On-Peak kW

In the event the Off-Peak kW is greater than twice the highest On-Peak kW established during the current month, the difference between such Off-Peak kW and twice the On-Peak kW shall be billed at 50% of the current month's On-Peak kW charge, in addition to the Demand Charge as stated above.

RATES (cont)

Energy Charge:

May – October Billing Cycles (Summer)	November – April Billing Cycles (Winter)
$ 0.14534 per kWh during On-Peak hours, plus $ 0.07019 per kWh during Off-Peak hours	$ 0.12779 per kWh during On-Peak hours, plus $ 0.06292 per kWh during Off-Peak hours

MINIMUM

The bill for service under this rate schedule will not be less than the applicable Bundled Standard Offer Service Basic Service Charge.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the On-Peak and Off-Peak periods during the month, as determined from readings of the Company's meter.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

On-Peak hours:	11:00 am – 9:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

ADJUSTMENTS (cont)

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

The contract period for all customers receiving service under this rate schedule will be one (1) year at the Company's option.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, which contains provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE RIDER SCHEDULE E-36 M
CLASSIFIED SERVICE
STATION USE SERVICE MEDIUM

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to Standard Offer electric service for start-up and/or auxiliary load requirements for generation plants with a power supply capacity requirement of less than 3 MW. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by individual customer contract. Special metering may be required such as bi-directional metering. This rate schedule may be used in conjunction with other applicable rate schedules; however, service under this schedule is not eligible for Direct Access.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP. Service under this schedule is generally provided at secondary voltage or primary voltage when the customer owns the distribution transformer(s).

OPTIONS

A. Customer may net the kWh output of their generator provided to APS through a purchase power contract or other arrangement against the electricity provided by APS to the Customer for station use. Under this option, the charges in this Schedule will not apply.

B. Company supplies the station use power needs to the customer at the rates and provisions in this rate rider schedule.

RATES

Customers shall be placed on a small or medium pricing tier annually, based on the maximum metered monthly demand, averaged over the summer months May through October, or if such load data is not available, other relevant data determined by the Company. If such average demand is greater than 3 MW the customer will be placed on Rate Schedule E-36 XL.

Small:
Customers placed on the small pricing tier shall be billed according to the rates and provisions in Rate Schedule E-32 XS, except for the unbundled basic service and revenue cycle service charges which are specified below.

Medium:
Customers placed on the medium pricing tier shall be billed according to the rates and provisions in Rate Schedule E-32 L, except for the unbundled basic service and revenue cycle service charges which are specified below.

Unbundled Basic Service Charge:		
For E-32 M and E-32 L		
Self-Contained Meters:	$ 1.344	per day, or
Instrument-Rated Meters:	$ 1.322	per day, or
Primary Voltage Meters:	$ 6.830	per day
Revenue Cycle Service Charges:		
E-32 XS		
Metering:		
Self-Contained Meters:	$ 0.403	per day, or
Instrument-Rated Meters:	$ 1.055	per day, or
Primary Voltage Meters:	$ 3.146	per day
Meter Reading:	$ 0.068	per day
Billing:	$ 0.075	per day
E-32 L		
Metering:		
Self-Contained Meters:	$ 0.345	per day, or
Instrument-Rated Meters:	$ 0.904	per day, or
Primary Voltage Meters:	$ 2.696	per day, or
Transmission	$ 22.192	per day
Meter Reading:	$ 0.058	per day
Billing:	$ 0.064	per day

INTERCONNECTION REQUIREMENTS

The customer must meet all interconnection requirements as determined by the Company. The customer is responsible for all costs associated with interconnection of the customer's generation facility to the Company's system.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-36 XL
CLASSIFIED SERVICE
STATION USE SERVICE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served.

APPLICATION

This rate schedule is applicable to Standard Offer electric service for start-up and/or auxiliary load requirements for generation plants with a Power Supply capacity requirement of greater than 3 MW. Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by individual customer contract. This rate schedule may be used in conjunction with other applicable Company rate schedules; however, any service under this schedule is not eligible for Direct Access.

TYPE OF SERVICE

The type of service provided under this rate schedule shall be three phase, 60 Hertz, at one standard voltage available within the vicinity of the customer's site.

RATES

The bill shall be the sum of the amounts included under A, B, and C below, including any applicable adjustments:

A. Basic Service

Basic Service Charge:	$ 6,912	per month

B. Metering Service

The monthly metering charge shall be 1.29% of the total metering cost specified in the Electric Supply Agreement between the Company and the customer. This percentage will be reduced to 0.35% when the customer provides all necessary metering equipment and is responsible for its replacement. The customer shall also be responsible for all applicable costs associated with communications facilities used to compile metered usage information.

C. Power Supply Service

The charge for Power Supply Service shall be the sum of 1 and 2 below:

1. T & D Capacity Rate:	$ 3.605	per kW of Contract Power Supply Capacity for service provided at secondary distribution voltage levels (less than 12.5 kV), or
	$ 3.423	per kW of Contract Power Supply Capacity for service provided at primary distribution voltage levels (12.5 kV to below 69 kV), or
	$ 0.035	per kW of Contract Power Supply Capacity for service provided at transmission voltage levels (69 kV or higher).

RATES (cont)

C. Power Supply Service (cont)

2. Power Supply/Energy/Ancillary Service Charge:	Hourly Pricing Proxy plus $ 0.00057 for each kWh used

CONTRACT PERIOD

Any applicable contract periods will be set forth in an Electric Supply Agreement between the customer and the Company.

CONNECTION COSTS

The customer will pay all applicable connection costs and system improvement costs not otherwise covered in this schedule as a non-refundable contribution in aid of construction, including any associated tax liability.

POWER SUPPLY CAPACITY

Power Supply Capacity kW shall be defined as the greater of:

(a) The amount of capacity (kW) reserved by the customer in the Electric Supply Agreement; or

(b) The highest 15 minute measured kW supplied by the Company, by voltage level, to accommodate the start-up of the customer's generation unit(s) plus any necessary auxiliary load (including generation auxiliary load and/or any other load requirements at the plant site that would otherwise be provided by the customer when the generation unit(s) are running).

If more than one generation unit is present at a single site, the Electric Supply Agreement may, at the Company's option, allow the customer to start one unit at a time. In this instance, Power Supply Capacity kW shall be defined as the greater of:

(a) The amount of capacity (kW) reserved by the customer in the Electric Supply Agreement; or

(b) The highest 15 minute measured kW supplied by the Company, by voltage level, to accommodate the start-up of one and only one customer generation unit at any given time plus any necessary auxiliary load (including any or all generation auxiliary load and/or any other load requirements at the entire plant site that would otherwise be provided by the customer when any or all generation unit(s) are running).

If, during any one billing period, the highest 15 minute measured kW supplied by the Company (by voltage level) exceeds the amount of Power Supply Capacity specified in the Electric Supply Agreement, the Power Supply Capacity reservation (by voltage level) shall be permanently increased to equal the higher measured kW. If the Company incurs additional connection costs to provide this added capacity, the customer is responsible for payment of these costs as specified herein.

DETERMINATION OF HOURLY PRICING PROXY

Hourly pricing proxy shall be calculated using the published day ahead Dow Jones Electricity Price Index. APS will calculate a weighted average using the day ahead hub pricing and volumes at Palo Verde, Four Corners, and Mead, for firm on-peak and off-peak prices as expressed on a per kWh basis, at the time Station Use power is supplied to the customer.

METERING

The Company will normally install a supply meter at the point of delivery to the customer and a generator meter(s) at the point(s) of output from each of the customer's generators. However, the customer can elect to supply this metering as long as it conforms to Company specifications. All meters will record integrated demand and energy on the same 15-minute interval basis as specified by the Company.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be
non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744, and XXXXX.

3. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

4. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commisison Decision No. 71448.

5. The bill is subject to 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 APS 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.

Service under this schedule is not subject to the Company's Adjustment Schedule PSA-1.

INTERCONNECTION REQUIREMENTS

The customer must meet all interconnection requirements as determined by the Company. The customer is responsible for all costs associated with interconnection of the customer's generation facility to the Company's system.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, which contains provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-40
CLASSIFIED SERVICE
AGRICULTURAL WIND MACHINE SERVICE

THIS RATE IS CANCELED EFFECTIVE XXXXX PER A.C.C. DECISION NO. XXXXX.

RATE SCHEDULE E-47
CLASSIFIED SERVICE
DUSK TO DAWN LIGHTING SERVICE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to outdoor lighting which operates only from dusk to dawn and where service can be supplied from the existing secondary facilities of the Company. Dusk is defined as the time between sunset and full night when a photocontrol senses the lack of sufficient sunlight and turns on the lights. Dawn is defined as the time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

RATES

The customer's bill shall be computed at the following rates for each type of standard facility and/or service utilized to provide outdoor lighting, plus any adjustments incorporated in this schedule:

I. FIXTURES (Includes Mounting Arm, if Applicable)

				RATES	
	Lumen	Watts	kWh	Company Owned	Customer Owned
A. Acorn	9,500 HPS	100	41	$27.88	$7.09
	16,000 HPS	150	69	30.85	8.89
B. Architectural	9,500 HPS	100	41	15.77	5.61
	16,000 HPS	150	69	18.33	7.45
	30,000 HPS	250	99	21.67	9.51
	50,000 HPS	400	153	26.60	13.63
	14,000 MH	175	72	21.99	8.98
	21,000 MH	250	101	24.88	11.02
	36,000 MH	400	159	30.98	15.08
	8,000 LPS	55	30	23.04	7.61
	13,500 LPS	90	50	27.11	9.12
	22,500 LPS	135	72	30.90	11.07
	33,000 LPS	180	90	37.16	13.03
C. Cobra/Roadway	5,800 HPS	70	29	8.93	3.94
	9,500 HPS	100	41	10.49	4.81
	16,000 HPS	150	69	13.05	6.66
	30,000 HPS	250	99	15.67	8.61
	50,000 HPS	400	153	21.18	12.25
	14,000 MH	175	72	15.21	7.72
	21,000 MH	250	101	17.70	9.57
	36,000 MH	400	159	23.20	13.22
	8,000 FL	100	38	17.67	3.81

RATES (cont)

I. FIXTURES (Includes Mounting Arm, if Applicable) (cont)

		Lumen	Watts	kWh	RATES Company Owned	RATES Customer Owned
D. Decorative Transit		9,500 HPS	100	41	$38.27	$8.58
		16,000 HPS	150	69	37.94	6.25
		30,000 HPS	250	99	43.59	12.20
E. Flood		30,000 HPS	250	99	20.94	9.67
		50,000 HPS	400	153	25.84	13.35
		21,000 MH	250	101	22.37	10.23
		36,000 MH	400	159	27.13	13.79
F. Post Top	Colonial Gray	8,000 FL	100	38	19.06	3.96
		9,500 HPS	100	41	10.82	5.07
	Colonial Black	9,500 HPS	100	41	12.49	5.25
	Decorative Transit	9,500 HPS	100	41	33.49	7.90
G. FROZEN		~~4,000 INC~~	~~295~~	~~103~~	~~$9.70~~	$3.87
		~~7,000 MV~~	~~175~~	~~73~~	~~12.82~~	5.42
		~~20,000 MV~~	~~400~~	~~150~~	~~25.19~~	10.48
	Brackets over 8 ft. and up to 16 ft. in length				1.78	--

FROZEN

NOTES:
1. Company Owned fixtures are those fixtures that the Company installs, owns, operates, and maintains.
2. Customer Owned fixtures are those fixtures where the customer installs and maintains the lighting fixtures, and the Company approves the installation, operates the fixtures, and replaces Company standard lamps only.
3. Listed kWhs reflect the assigned monthly energy usage for each type of fixture and are used to determine any applicable transmission, system benefit, distribution, energy and adjustment charges.
4. HPS = High Pressure Sodium
5. MH = Metal Halide
6. LPS = Low Pressure Sodium
7. FL = Fluorescent
8. INC = Incandescent. Incandescent lighting charges are applicable and available only to those customers being served and those installations in service on April 21, 1983.
9. MV = Mercury Vapor. Mercury Vapor lighting charges are applicable and available only to those customers being served and those installation in service on June 1, 1987 in accordance with A.R.S. §49-1104(A).

RATES (cont)

II. POLES

			Height	RATES Company Owned
A. Anchor Base Mounted (Flush)	Round Steel	1 Simplex Adapter	12 ft.	$12.61
			22 ft.	14.20
			25 ft	15.36
			30 ft	17.65
			32 ft	18.54
	Round Steel	2 Simplex Adapters	12 ft.	13.45
			22 ft.	15.45
			25 ft.	16.12
			30 ft.	18.73
			32 ft.	19.98
	Square Steel	5"	13 ft.	14.46
			15 ft.	12.93
			23 ft.	15.33
			25 ft.	16.85
			28 ft.	18.71
			32 ft.	18.61
	Concrete		12 ft.	43.10
	Fiberglass		12 ft.	36.50
	Decorative Transit	4"	16 ft.	35.58
	Decorative Transit	6"	30 ft.	68.70
B. Anchor Base Mounted (Pedestal)	Round Steel	1 Simplex Adapter	12 ft.	12.14
			22 ft.	13.72
			25 ft.	14.87
			30 ft.	17.19
			32 ft.	18.05
	Round Steel	2 Simplex Adapters	12 ft.	12.97
			22 ft.	14.48
			25 ft.	15.63
			30 ft.	18.25
			32 ft.	19.50
		3 Bolt Arm	32 ft.	22.41
	Square Steel	5"	13 ft.	13.99
			15 ft.	14.30
			23 ft.	14.84
			25 ft.	16.38
			28 ft.	18.20
			32 ft.	18.90

RATES (cont)

II. POLES (cont)

			Height	RATES Company Owned
C. Direct Bury	Round Steel		19 ft.	$19.09
			30 ft.	14.90
			38 ft.	18.19
		Self Support	40 ft.	22.41
		Stepped	49 ft.	67.36
	Square Steel	4"	34 ft.	16.45
		5"	20 ft.	15.62
			30 ft.	16.28
			38 ft.	17.67
	Decorative Transit		41 ft. 6	21.22
	Decorative Transit		47 ft.	26.43
	Steel Distribution Pole (for lighting		35 ft.	24.40
D. Post Top	Decorative Transit Anchor Base		16 ft.	36.35
	Gray Steel/Fiberglass		23 ft.	12.60
	Black Steel		23 ft.	13.90
E. FROZEN	~~Wood Poles~~		~~30 ft.~~	~~$9.28~~
			~~35 ft.~~	~~9.28~~
			~~40 ft.~~	~~13.19~~

FROZEN

NOTES:
1. All distribution lines required to serve dusk to dawn facilities are owned by the Company.
2. Monthly rates for all new Company owned poles include up to 100 feet of overhead secondary wire, or up to 100 feet of underground secondary line if customer provides earthwork and conduit (excluding the overhead to underground transition). Any additional wire required (over and above the first 100 feet provided) to install fixtures is subject to the additional monthly wire charges specified in Section IV.1 below.
3. When adding lighting fixtures to an existing Company owned pole, any and all additional distribution wire required is subject to the additional monthly wire charges specified in Section IV.1 below.
4. Any and all distribution wire required to serve lighting facilities placed on a customer owned pole, whether new or existing, is subject to the additional monthly wire charges specified in Section IV.1 below.

III. ANCHOR BASE

		Height	RATES Company Owned
A. Flush		4 ft.	$10.27
		6 ft.	12.25
B. Pedestal		8 ft.	14.03
	For 32' Round Steel Pole only	4 ft. 6"	9.73

IV. RATES FOR OPTIONAL OR ADDITIONAL EQUIPMENT

	RATES Company Owned
1. Each 100 feet of overhead secondary wire, or each 100 feet of underground secondary wire if customer provides earthwork and conduit.	$3.63
2. Additional maintenance charge for HPS lamp and luminaire that is not accessible by bucket truck.	2.90
3. Additional maintenance charge for MH lamp and luminaire that is not accessible by bucket truck.	6.26

TRIP CHARGE

When Company is not the responsible party contracted for the regular maintenance of a dusk to dawn lighting system owned by a city, town or other governmental entity, a $100.00 trip charge per light will be charged when customer requests a disconnect and/or reconnect of service in order to accommodate the maintenance activities of the customer or its designee(s) on their dusk to dawn equipment. The trip charge will also apply when customer request disconnect or reconnect for non-maintenance purposes.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission No. 71448 and XXXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. XXXXX.

7. The bill is subject to 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 APS 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.

SPECIAL PROVISIONS

1. The 4,000 and 7,000 lumen lamps use an open glass diffuser. All units are controlled by a photoelectric switch.

2. The customer is not authorized to make connections to the lighting circuits or to make attachments.

3. Should a customer request relocation of a dusk-to-dawn lighting installation, the costs of such relocation shall be paid by the customer.

4. The Company cannot guarantee that all dusk to dawn facilities will always operate as intended. Therefore, the customer will be responsible for notifying the Company when the dusk to dawn facilities are not operating as intended. The Company will use reasonable efforts to complete normal maintenance (replacement of lamps, photocontrols or fixtures) within ten (10) working days from notification by customer; however, if the maintenance requires cable replacement or repairs, the Company shall use reasonable efforts to complete said repairs within twenty (20) working days.

5. The customer's bill will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

6. The customer may cancel a lighting service agreement by payment of the bill including the applicable tax adjustment, multiplied by the number of remaining months of the initial agreement, or the calculated installation and removal costs for the extension, whichever is lower.

7. Lighting equipment which is not specified in this rate schedule will be billed at the rates corresponding to the most similar equipment, as determined by the Company.

8. Lighting Equipment and services with an initial Company cost exceeding $25,000 shall require a financial liability agreement between the Company and the customer.

NON-STANDARD FACILITIES – CUSTOMER OWNED

When the customer requests any non-standard dusk-to-dawn lighting facilities (non-standard being defined as any equipment not listed in the Company's Transmission and Distribution Construction Standards book), the customer will own, operate and maintain all components to the system excluding the distribution facilities installed by the Company to serve the lighting system. Monthly bills rendered for non-standard facilities will be computed at the following rates, plus any adjustments incorporated in this schedule. KWh will be determined by the Company, based on the rated wattage of the lighting equipment and an estimated average hourly usage per month.

A.	Service Charge	$3.47	per installed lamp per month
B.	Energy Charge	$0.06577	per kWh per month

If, at the Company's discretion, the customer chooses to have the Company maintain the entire non-standard facility, the Company may require the customer to enter into a separate maintenance agreement which may be subject to additional charges mutually agreed upon by the Company and the customer.

CONTRACT PERIOD

All Dusk-to-Dawn lighting installations will require a written agreement for service for a minimum of three (3) years, or longer at Company's option.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RIDER RATE SCHEDULE E-56
CLASSIFIED SERVICE
PARTIAL REQUIREMENTS SERVICE

AVAILABILITY

This rider rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and suitable voltage are adjacent to the premises served and when all applicable provisions described herein have been met.

APPLICATION

This rider rate schedule is applicable to retail Customers who obtain any part of their electric requirements from on-site generation equipment with a continuous nameplate rating of 100 kW or greater for other than emergency purposes, requiring Supplemental and Back-up or Maintenance Power and energy from the Company. Direct access customers are not eligible for service under this rate schedule. All provisions of the Customer's applicable retail rate schedule will apply except those specifically modified herein. Total measured demand at the Customer's meter will be used to determine the applicable retail rate schedule.

DEFINITIONS

1. Back-up Contract Demand - The specified demand, in kilowatts, of Back-up Power that the Customer contracts with the Company to supply and which the Company agrees to have available for delivery to the Customer. The Back-up Contract Demand shall be established by agreement between Customer and Company. The level of Back-up Contract Demand shall not exceed the total output capacity of the Customer's generation facilities.

2. Back-up Power - The kW of Back-up Contract Demand supplied by the Company to the Customer. Back-up Power shall be determined for each day of the Billing Period containing on-peak hours. The kW of Back-up Power each day shall be the kW for the fifteen (15) minute period of the Customer's greatest use of Back-up Power during the on-peak hours of the day. The Back-up Power for the Billing Period shall be the sum of the Back-up Power for each day of the Billing Period. For each fifteen minute period, Back-up Power shall equal the Measured Demand minus the Supplemental Contract Demand but shall not be less than zero nor greater than the Back-up Contract Demand.

3. Billing Period - The period of approximately thirty (30) days intervening between regular successive meter reading dates. There shall be twelve (12) billing periods per year.

4. Excess Power - Excess Power is power supplied by the Company to the Customer in excess of the Total Contract Demand. The kW of Excess Power for the Billing Period shall be the kW for the fifteen (15) minute period of the Customer's greatest use of Excess Power during the Billing Period. For each fifteen minute period, Excess Power shall equal the Measured Demand minus the Total Contract Demand but shall not be less than zero.

5. Maintenance Power - Electric power and energy made available by the Company to a Customer during the scheduled maintenance periods established in accordance with the provisions of this schedule to replace Back-up Power. Maintenance Power shall not exceed the Back-up Contract Demand.

6. Measured Demand - The fifteen (15) minute Demands (Power) in kilowatts as shown by or computed from the readings of the Power (Demand) meter located at the Company's point of delivery for on-peak and off-peak periods during the Billing Period.

DEFINITIONS (cont)

7. Measured Energy - The electric energy in kilowatt-hours as shown by or computed from the readings of the kilowatt-hour meter located at the Company's point of delivery.

8. Supplemental Contract Demand - The specified demand in kilowatts of Supplemental Power that the Customer contracts with the Company to supply and which the Company agrees to have available for delivery to the Customer

9. Supplemental Power – The kW of Supplemental Contract Demand supplied by the Company to the Customer. The kW of Supplemental Power for the Billing Period shall be the kW for the fifteen (15) minute period of the Customer's greatest use of Supplemental Power during the Billing Period. For each fifteen minute period, Supplemental Power shall equal the Measured Demand but shall not be less than zero nor greater than the Supplemental Contract Demand.

10. Total Contract Demand - The sum of the Supplemental Contract Demand and the Back-up Contract Demand.

DETERMINATION OF SUPPLEMENTAL AND BACKUP CONTRACT DEMAND

The Supplemental Contract and Backup Demand shall be initially established by agreement between the Customer and the Company, and shall be reset annually based on the average daily maximum Measured Demand over the six months, May through October of the most recent year.

MONTHLY RATES

The bill shall be the sum of the amounts computed below, including any applicable adjustments:

A. Basic Service: The Basic Service and Revenue Cycle Service Charges included in the customer's applicable General Service rate schedule will apply each month.

B. Supplemental Power and Associated Energy: Supplemental Power and Associated Energy will be provided in accordance with the rate levels contained in the customer's applicable General Service rate schedule, excluding the monthly Basic Service and Revenue Cycle Service Charges, and also excluding delivery charges associated with Back-up Contract Demand.

C. Delivery Charges: The unbundled delivery charge contained in the customer's applicable General Service rate schedule multiplied by the amount of Back-up Contract Demand.

D. Back-up Power Charges:

Rate Schedule E-34 Customer - On-Peak:	$ 0.590	per kW Day
Rate Schedule E-32 Customer - On-Peak:	$ 0.120	per kW Day
During Scheduled Maintenance:	One Half (1/2) On-Peak Charge	
Off Peak:	No Charge	
On-Peak Periods:	9 a.m. to 9 p.m., weekdays or as reflected in the customer's otherwise applicable retail rate schedule	

Back-up Power Charges (cont):

Off-Peak Periods:	All other hours

The Power Charge for Back-up Power is billed on a per day basis and is based on the fifteen (15) minute period of the Customer's greatest use of Back-up Power during on-peak hours each on-peak day. For each fifteen minute period, Back-up Power shall equal the Measured Demand minus the Supplemental Contract Demand but shall not be less than zero nor greater than the Back-up Contract Demand.

E. Excess Power Charges:

Secondary Service:	$ 54.802	per kW
Primary Service:	$ 52.019	per kW
Transmission Service:	$ 38.187	per kW

F. Back-up, Maintenance and Excess Energy: All Back-up, Maintenance, and Excess Energy shall be billed in accordance with the customer's applicable General Service rate schedule.

MAINTENANCE REQUIREMENTS

Maintenance energy shall be defined as energy supplied to Customer to replace energy normally supplied by the Customer's generator(s) during an authorized Scheduled Maintenance period.

Maintenance periods shall not exceed 30 days per generation unit during any consecutive 12-month period and must be scheduled during the non-Summer billing months, as defined in the Customer's applicable general service rate schedule. Customer shall provide Company with its planned maintenance schedule 90 days in advance of any planned maintenance in order for the Company to coordinate customer's scheduled maintenance with that of the Company. Upon review, Company shall either approve customer's planned maintenance schedule or notify customer of alternate acceptable periods. Customer, in turn, shall notify the Company of an acceptable alternate maintenance period(s), and shall also confirm with the Company its intention to perform its planned maintenance 45 days prior to the actual commencement date of the planned maintenance period.

METERING

The Company will install, at the customer's expense, a bi-directional meter at the point of delivery to the customer (Supply Meter) and meter(s) at the point(s) of output from each of the customer's generators (Generator Meter) if required. All meters will record integrated demand and energy on the same 15- minute interval basis as specified by the Company.

TOTAL CONTRACT DEMAND, SUPPLEMENTAL CONTRACT DEMAND, AND BACK-UP CONTRACT DEMAND

The Customer shall contract for Total Contract Demand. This shall be the sum of the Supplemental Contract Demand and the Back-up Contract Demand. The Customer may elect to increase Total Contract Demand by increasing Supplemental Contract Demand and/or Back-up Contract Demand prospectively at any time, provided there are facilities of adequate capacity, by providing notice to the Company. Any increase in Total Contract Demand shall establish a new Total Contract Demand which shall be in effect for the term of the contract, unless superseded by subsequent increases in Total Contract Demand.

TERMINATION PROVISION

Should Customer cease to operate his generation unit(s) for 60 consecutive days during periods other than planned scheduled maintenance periods, Company reserves the option to terminate the Agreement for service under this rate schedule with Customer.

CONTRACT PERIOD

As provided in the Electric Supply Agreement between Company and Customer.

UNUSUAL UTILITY OPERATING CONDITIONS

If the Company is in need of additional power requirements due to equipment failure or other unusual conditions, the Customer may provide excess generation to Company at Company's request. The Company will pay the Customer for any energy purchased at the per kWh monthly firm purchase rate which is negotiated on a case-by-case basis.

TERMS AND CONDITIONS

Customer must enter into an Agreement for Interconnection and an Electric Supply Agreement which shall establish all details related to interconnection and other required service standards. Qualifying Cogeneration and Small Power Production Facilities (QFs) meeting Public Utility Regulatory Policy Act of 1978 criteria shall be permitted to sell excess power and energy subject to the provisions and rates specified in a Purchase Supply Agreement between Company and Customer. Customers who install facilities that do not meet QF standards will not have the right to sell power and energy to Company under this rate schedule. However, should Customer desire to do so, Customer may seek to enter into a new Service Agreement which would set forth the applicable purchase rates, terms and conditions for interconnection and for the sale of excess power to the Company.

RATE SCHEDULE E-58
CLASSIFIED SERVICE
STREET LIGHTING SERVICE

AVAILABILITY

This rate schedule is available in those portions of cities, towns and unincorporated communities in which Company does a general retail electric business and where Company has installed a multiple or series street lighting system of adequate capacity for the service to be rendered.

APPLICATION

This rate schedule is applicable to service for continuous lighting, from dusk to dawn, of public streets, alleys, thoroughfares, public parks and playgrounds by use of Company's facilities where such service for the entire area is contracted for from the Company by the city, town, other governmental agencies, or a responsible individual for unincorporated communities. Dusk is defined as the time between sunset and full night when a photocontrol senses the lack of sufficient sunlight and turns on the lights. Dawn is defined as the time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

RATES

The bill shall be computed at the following rates for each type of standard facility and/or service utilized to provide street lighting, plus any adjustments incorporated in this schedule:

I. FIXTURES (Includes Mounting Arm, if Applicable)

				RATES	
	Lumen	Watts	kWh	Investment by Company	Investment by Others
A. Acorn	9,500 HPS	100	41	$ 27.88	$9.39
	16,000 HPS	150	69	30.85	11.79
B. Architectural	9,500 HPS	100	41	15.77	7.44
	16,000 HPS	150	69	18.33	9.89
	30,000 HPS	250	99	21.67	12.64
	50,000 HPS	400	153	26.60	18.14
	14,000 MH	175	72	21.99	11.91
	21,000 MH	250	101	24.88	14.64
	36,000 MH	400	159	30.98	20.06
	8,000 LPS	55	30	23.04	10.05
	13,500 LPS	90	50	27.11	12.06
	22,500 LPS	135	72	30.90	14.67
	33,000 LPS	180	90	37.16	17.26
C. Cobra/Roadway	5,800 HPS	70	29	8.93	5.23
	9,500 HPS	100	41	10.49	6.38
	16,000 HPS	150	69	13.05	8.85
	30,000 HPS	250	99	15.67	11.46
	50,000 HPS	400	153	21.18	16.32

I. FIXTURES (Includes Mounting Arm, if Applicable) (cont):

					RATES	
		Lumen	Watts	kWh	Investment By Company	Investment By Others
C. Cobra/Roadway (cont.)		14,000 MH	175	72	$15.21	$10.26
		21,000 MH	250	101	17.70	12.72
		36,000 MH	400	159	23.20	17.60
		8,000 FL	100	38	17.67	5.06
D. Decorative Transit		9,500 HPS	100	41	38.27	11.35
		16,000 HPS	150	69	37.94	12.57
		30,000 HPS	250	99	43.59	16.18
E. Flood		30,000 HPS	250	99	20.94	12.86
		50,000 HPS	400	153	25.84	17.77
		21,000 MH	250	101	22.37	13.59
		36,000 MH	400	159	27.13	18.35
F. Post Top	Colonial Gray	8,000 FL	100	38	19.06	5.26
		9,500 HPS	100	41	10.82	6.72
	Colonial Black	9,500 HPS	100	41	12.49	6.96
	Decorative	9,500 HPS	100	41	33.49	10.44
G. FROZEN		~~4,000 INC~~	~~295~~	~~103~~	~~$9.70~~	$5.23
		~~7,000 MV~~	~~175~~	~~73~~	~~12.82~~	7.23
		~~11,000 MV~~	~~250~~	~~96~~	~~16.04~~	9.62
		20,000 MV	400	150	25.19	14.00

FROZEN

NOTES:

1. Investment by Company. These rates are applicable where the Company provides the initial investment to purchase and install all facilities necessary for street lighting service. The Company will own, operate, and maintain the street lighting system.
2. Investment by Others. These rates are applicable in those instances where the requesting entity or individual purchases and installs the street lighting facilities at their own expense and in accordance with Company specifications. These rates will also apply in the instance where the customer provides a non-refundable advance to the Company to cover the Company's cost of purchasing and installing the street lighting system. The Company retains ownership of the street lighting system and provides operation and maintenance for all facilities.
3. Listed kWhs reflect the assigned monthly energy usage for each type of fixture and are used to determine any applicable transmission, system benefit, distribution, energy and adjustment charges.
4. HPS = High Pressure Sodium
5. MH = Metal Halide
6. LPS = Low Pressure Sodium
7. FL = Fluorescent
8. INC = Incandescent. Incandescent lighting charges are applicable and available only to those customers being served and those installations in service on November 1, 1986.
9. MV = Mercury Vapor. Mercury Vapor lighting charges are applicable and available only to those customers being served and those installation in service on November 1, 1986 in accordance with A.R.S. §49-1104(A).

II. POLES

				RATES	
			Height	Investment By Company	Investment By Others
A. Anchor Base Mounted (Flush)	Round Steel	1 Simplex Adapter	12 ft.	$12.61	$1.74
			22 ft.	14.20	1.95
			25 ft.	15.36	2.12
			30 ft.	17.65	2.43
			32 ft.	18.54	2.46
		2 Simplex Adapters	12 ft.	13.45	1.86
			22 ft.	15.45	2.14
			25 ft.	16.12	2.22
			30 ft.	18.73	2.58
			32 ft.	19.98	2.76
	Square Steel	5"	13 ft.	14.46	1.99
			15 ft.	12.93	1.78
			23 ft.	15.33	2.10
			25 ft.	16.85	2.31
			28 ft.	18.71	2.57
			32 ft.	18.61	2.56
	Concrete		12 ft.	43.10	5.94
	Fiberglass		12 ft.	36.50	5.03
	Decorative Transit Pedestrian	4"	16 ft.	35.58	4.90
	Decorative Transit	6"	30 ft.	68.70	9.46
B. Anchor Base Mounted (Pedestal)	Round Steel	1 Simplex Adapter	12 ft.	12.14	1.67
			22 ft.	13.72	1.89
			25 ft.	14.87	2.05
			30 ft.	17.19	2.37
			32 ft.	18.05	2.49
		2 Simplex Adapters	12 ft.	12.97	1.78
			22 ft.	14.48	1.99
			25 ft.	15.63	2.15
			30 ft.	18.25	2.51
			32 ft.	19.50	2.68
		3 Bolt Arm	32 ft.	22.41	3.08
	Square Steel	5"	13 ft.	13.99	1.93
			15 ft.	14.30	1.96
			23 ft.	14.84	2.05
			25 ft.	16.38	2.27
			28 ft.	18.20	2.51
			32 ft.	18.90	2.59

II POLES (cont)

			Height	RATES Investment By Company	RATES Investment By Others
C. Direct Bury	Round Steel		19 ft.	$19.09	$2.63
			30 ft.	14.90	2.76
			38 ft.	18.19	2.83
		Self Support	40 ft.	22.41	3.54
		Stepped	49 ft.	67.36	9.29
	Square Steel	4"	34 ft.	16.45	2.85
		5"	20 ft.	15.62	2.58
			30 ft.	16.28	2.68
			38 ft.	17.67	3.07
	Decorative Transit		41 ft 6	21.22	3.12
	Decorative Transit		47 ft.	26.43	3.89
	Steel Distribution Pole (for lighting only)		35 ft.	24.40	3.21
D. Post Top	Decorative Transit Anchor Base		16 ft.	36.35	5.00
	Gray Steel/Fiberglass		23 ft.	12.60	2.07
	Black Steel		23 ft.	13.90	2.29
E. Existing distribution pole suitable for streetlight use				1.53	--

F. FROZEN	~~Wood Poles~~		~~30 ft.~~	~~$9.28~~	$1.61
			~~35 ft.~~	~~9.28~~	1.53

FROZEN

NOTE: The monthly rate for all new poles includes up to 300 feet of overhead secondary wire, or up to 300 feet of underground secondary wire if the customer provides earthwork and conduit (excluding the underground to overhead transition).

III. ANCHOR BASE

		Height	RATES Investment by Company	RATES Investment By Others
A. Flush		4 ft.	$10.27	$1.41
		6 ft.	12.25	2.12
B. Pedestal		8 ft.	14.03	2.45
	For 32' Round Steel Pole only	4 ft. 6"	9.73	1.69

IV. CHARGES FOR OPTIONAL OR ADDITIONAL EQUIPMENT

	RATES Company Owned
Underground Circuit Charges:	
a. ~~Per foot of cable, installed under paving~~	$0.16
~~b. Per foot of cable, not installed under paving~~	$0.06

FROZEN

TRIP CHARGE

When Company is not the responsible party contracted for the regular maintenance of a street lighting system owned by a city, town or other governmental entity, a $100.00 trip charge per light will be charged when Customer requests a disconnect and/or reconnect of service in order to accommodate the maintenance activities of the Customer or its designee(s) on their street light equipment. The trip charge will also apply when Customer request disconnect or reconnect for non-maintenance purposes.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744 Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission No. 71448, and XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to 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 APS 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.

SPECIAL PROVISIONS

1. Street lighting facilities installed under this rate schedule are of the type currently being furnished by Company as standard at the time service is initially requested. Standard facilities are those listed in the Company's Transmission and Distribution Construction Standards book.

2. The Company cannot guarantee that streetlighting facilities will always operate as intended. Therefore, the customer will be responsible for notifying the Company when the streetlighting facilities are not operating as intended. The Company will use reasonable efforts to complete normal maintenance (replacement of lamps, photocontrols or fixtures) within ten (10) working days from notification by customer; however, if the maintenance requires cable replacement or repairs, the Company shall use reasonable efforts to complete said repairs within twenty (20) working days.

SPECIAL PROVISIONS (cont)

3. The customer's bill will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

4. Lighting equipment which is not specified in this rate schedule will be billed at the rates corresponding to the most similar equipment, as determined by the Company.

NON-STANDARD FACILITIES

Non-standard facilities (non-standard being defined as any facility not listed in the Company's Transmission and Distribution Construction Standards book) do not qualify for this rate schedule. At the Company's discretion, such facilities may be served under another of the Company's rate schedules.

EXTENSION OF STREET LIGHTING SYSTEM

The Company will extend its standard street lighting system up to a distance of 300 feet for each additional lighting installation without cost at the request of the customer. When the extension is underground the customer will provide earthwork as specified in the Company's Service Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services; or, at the applicant's request, the Company will provide such earthwork and the applicant will be required to pay a non-refundable contribution in aid of construction equal to the cost of such earthwork. Any additional extension required (over and above the first 300 feet) will be provided by Company for a contribution in aid of construction equal to the cost of the additional extension.

Extensions to isolated areas requiring a substantial extension of the electric distribution system, as opposed to an extension of the street lighting system, will require a special study to determine the terms and conditions under which the Company will undertake such an extension.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-59
CLASSIFIED SERVICE
GOVERNMENT OWNED STREET LIGHTING SYSTEMS

AVAILABILITY

This rate schedule is available in those portions of cities, towns and unincorporated communities in which the Company does a general retail electric business and where the customer has installed or purchased a multiple or series street lighting system and the Company has distribution facilities of adequate capacity for the service to be rendered.

APPLICATION

This rate schedule is applicable to Standard Offer electric service for continuous lighting, from dusk to dawn, of public streets, alleys, thoroughfares, public parks and playgrounds by use of the customer's facilities where such service for the whole area is contracted for from the Company pursuant to the terms set forth herein by the city, town, other governmental entities, or a responsible individual for unincorporated communities. Dusk is defined as the time between sunset and full night when a photocontrol senses the lack of sufficient sunlight and turns on the lights. Dawn is defined as the time between full night and sunrise when a photocontrol senses sufficient sunlight to turn off lights.

The customer will own, operate, and maintain the street lighting system including lamps and glass replacements but excluding distribution facilities installed by the Company to serve the lighting system.

RATES

The bill shall be computed at the following rates plus any adjustments incorporated in this schedule:

Service Charge:	$2.89	per installed lamp
Energy Charge:	$ 0.05876	per kWh

TRIP CHARGE

When Company is not the responsible party contracted for the regular maintenance of a street lighting system owned by a city, town or other governmental entity, a $100.00 trip charge per light will be charged when customer requests a disconnect and/or reconnect of service in order to accommodate the maintenance activities of the customer or its designee(s) on their street light equipment. The trip charge will also apply when customer request disconnect or reconnect for non-maintenance purposes.

ADJUSTMENTS

1. The bill is subject the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No 71448 and XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

ADJUSTMENTS (cont)

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No.67744 and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to 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 APS 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.

SPECIAL PROVISIONS

1. Billed energy is based upon the summation of the contracted energy rating of installed facilities specified in the streetlighting contract.

2. The customer's bill will not be reduced due to lamp, photocontrol or cable repair or replacement outages.

3. Presently installed units which do not conform to the types specified in Rate Schedule E-58 will be billed in accordance with the type which is most nearly like such units.

EXTENSION OF COMPANY DISTRIBUTION SYSTEM

The Company will extend its standard street lighting system up to a distance of 300 feet for each additional lighting installation without cost at the request of the customer. When the extension is underground the customer will provide earthwork as specified in of the Company's Service Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services; or, at the customer's request, the Company will provide such earthwork and the applicant will be required to pay a non-refundable contribution in aid of construction equal to the cost of such earthwork. Any additional extension required (over and above the first 300 feet) will be provided by Company for a contribution in aid of construction equal to the cost of the additional extension.

Extensions to isolated areas requiring a substantial extension of the electric distribution system, as opposed to an extension of the street lighting system, will require a special study to determine the terms and conditions under which the Company will undertake such an extension.

CONTRACT PERIOD

The contract period for service under this rate schedule shall be a fixed period of not less than 1 year and not more than 20 years, as agreed to by the customer and as specified in the streetlighting contract.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-67
CLASSIFIED SERVICE
MUNICIPAL LIGHTING SERVICE
CITY OF PHOENIX

AVAILABILITY

This rate schedule is available within the City of Phoenix at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to Standard Offer electric service furnished for the lighting of alleys, buildings, and other public places owned or maintained by the City. Streetlighting service is not eligible for this schedule. Service to traffic signals is limited to those installations being served as of January 31, 1985, under the Agreement of April 4, 1930, as modified, between Central Arizona Light and Power Company and the City of Phoenix, and no new or reconnected traffic signal installations may be served after that time. Service must be supplied at one site through one point of delivery and measured through one meter. Direct Access service is not available under this rate schedule.

This schedule is not applicable to breakdown, standby, supplemental, or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage (as may be selected by customer, subject to availability at the customer's site).

RATES

The bill shall be computed at the following rate plus any adjustments incorporated in this schedule:

Energy Charge: $ 0.05057 per kWh

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

ADJUSTMENTS (cont)

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448, and XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No 71448.

6. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to 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 APS 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.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, which contains provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-114
CLASSIFIED SERVICE – SHARE THE LIGHT
LOWER MIAMI AND CLAYPOOL STREET LIGHTING

THIS RATE IS CANCELED EFFECTIVE XXXXX PER ACC DECISION NO. XXXXX.

RATE SCHEDULE E-116
CLASSIFIED SERVICE – SHARE THE LIGHT
CENTRAL HEIGHTS AND COUNTRY CLUB MANOR
STREET LIGHTING

THIS RATE IS CANCELED EFFECTIVE XXXXX PER ACC DECISION NO. XXXXX.

RATE SCHEDULE E-145
CLASSIFIED SERVICE – SHARE THE LIGHT
AJO HEIGHTS STREET LIGHTING

THIS RATE IS CANCELED EFFECTIVE XXXXX PER ACC DECISION NO. XXXXX.

RATE SCHEDULE E-221
CLASSIFIED SERVICE
WATER PUMPING SERVICE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to Standard Offer electric service required for irrigation pumping or for water utilities for pumping potable water to serve the citizens of a city, town, or unincorporated community. Service must be supplied at one point of delivery and measured through one meter. Direct Access customers are not eligible for service under this schedule.

Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site.

RATES

The bill shall be computed at the following rates or minimum rates, whichever is greater, plus any adjustments incorporated in this schedule:

Basic Service Charge:	$ 0.588	per day
Demand Charge:	$ 0.867	per kW
Energy Charge:	$ 0.11680	per kWh for the first 240 kWh, plus
	$ 0.07940	per kWh for the next 275 kWh per kW, plus
	$ 0.06519	per kWh for all additional kWh

MINIMUM

The bill for service under this rate schedule will not be less than $0.588 per day plus $0.867 for each kW of the highest kW established during the 12 months ending with the current month, or the minimum kW specified in the Electric Service Agreement, whichever is greater.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

POWER FACTOR (cont)

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month, as determined from readings of the Company's meter, or at the Company's option, by test.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744, and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. XXXX.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 Schedule pursuant to Arizona Corporation Commission Decision No. XXXX.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

The contract period for customers receiving service under this rate schedule will be one (1) year or longer. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, which contains provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-221-8T
CLASSIFIED SERVICE
WATER PUMPING SERVICE – TIME-OF-USE

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to Standard Offer electric service required for irrigation pumping or for water utilities for pumping potable water to serve the citizens of a city, town, or unincorporated community. Service must be supplied at one point of delivery and measured through one meter. Direct Access customers are not eligible for service under this schedule.

Rate selection is subject to paragraphs 3.2 and 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site.

RATES

The bill shall be computed at the following rates or minimum rate, whichever is greater, plus any adjustments incorporated in this schedule:

Basic Service Charge:	$ 1.015	per day
Demand Charge:	$ 4.249	per On-Peak kW, plus
	$ 3.486	per Off-Peak kW
Energy Charge:	$ 0.09576	per kWh during On-Peak hours, plus
	$ 0.05151	per kWh during Off-Peak hours

MINIMUM

The bill for service under this rate schedule will not be less than $1.015 per day plus $1.901for each kW of the highest kW established during on or off peak hours during the 12 months ending with the current month, or the minimum kW specified in the Electric Service Agreement, whichever is greater.

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be
non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

POWER FACTOR (cont)

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVa may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the On-Peak and Off-Peak periods during the month, as determined from readings of the Company's meter, or at the Company's option, by test.

TIME PERIODS

For the purpose of this rate schedule, the On-Peak time period is between 11 a.m. and 9 p.m.,weekdays only. All hours not included in the specified On-Peak period are designated as Off-Peak hours. Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1. The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2. The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No 71448, and XXXX.

3. The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744, and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744, and Arizona Corporation Commission Decision No. 71448.

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 Schedule pursuant to Arizona Corporation Commission Decision No. xxxxx.

ADJUSTMENTS (cont)

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

The contract period for customers receiving service under this rate schedule will be one (1) year or longer. At the Company's option, the contract period will be three (3) years or longer where additional distribution construction is required to serve the customer.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, which contains provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE E-249
CLASSIFIED SERVICE – SHARE THE LIGHT
CAMP VERDE STREET LIGHTING

THIS RATE IS CANCELED EFFECTIVE XXXXX PER ACC DECISION NO. XXXXX.

RATE SCHEDULE GS-SCHOOLS M
GENERAL SERVICE (0 kW – 400 kW)
TIME OF USE
ELEMENTARY AND SECONDARY SCHOOLS

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to Standard Offer electric service for private and public elementary and secondary schools (K-12) whose average monthly maximum demand is less than or equal to 400 kW per month.

The Company will place the Customer on the applicable Rate Schedule GS-SCHOOLS M or GS-SCHOOLS L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination. The Company may also place the Customer on the Applicable Rate Schedule during the year, if the Customer has experienced a significant and permanent change in load as determined by the Company. Such placement will be based on available information.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services. Availability of this rate is subject to the availability of required metering equipment and completion of necessary enhancements to the Company's billing system.

This schedule is not applicable to breakdown, standby, supplemental, or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

Service under this schedule is generally provided at secondary voltage; primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates, plus any adjustments incorporated in this rate schedule:

Basic Service Charge:

For service through Self-Contained Meters:	$ 0.658	per day, or
For service through Instrument-Rated Meters:	$ 1.328	per day, or
For service at Primary Voltage:	$ 3.477	per day, or
For service at Transmission Voltage:	$ 26.855	per day

RATES (cont)

Demand Charge:

Secondary Service:	$ 8.294	per kW for the first 100 kW, plus
	$ 3.644	per kW for all additional kW, or
Primary Service:	$ 7.578	per kW for the first 100 kW, plus
	$ 2.927	per kW for all additional kW, or
Transmission Service:	$ 5.546	per kW for the first 100 kW, plus
	$ 0.895	per kW for all additional kW

Energy Charge:

June – August Billing Cycles (Summer Peak)
$ 0.17687 per kWh during On-Peak hours, plus $ 0.13102 per kWh during Shoulder-Peak hours, plus $ 0.06647 per kWh during Off-Peak hours

May, September, and October Billing Cycles (Summer Shoulder)	November – April Billing Cycles (Winter)
$ 0.15274 per kWh during On-Peak hours, plus $ 0.11314 per kWh during Shoulder-Peak hours, plus $ 0.0574 per kWh during Off-Peak hours	$ 0.11799 per kWh during On-Peak hours, plus $ 0.0874 per kWh during Shoulder-Peak hours, plus $ 0.04434 per kWh during Off-Peak hours

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, including determination of Monthly Maximum Demands, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month as determined from readings of the Company's meter.

DETERMINATION OF KW (cont)

For the purpose of placement on this rate, the Average Monthly Maximum Demand shall equal the average of the Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum kW provided by the Customer and approved by the Company.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

Summer Peak (June - August)

On-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Shoulder-Peak hours:	11:00 am – 3:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Summer Shoulder (May, September and October)

On-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Shoulder-Peak hours:	11:00 am – 3:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Winter (November - April)

On-Peak hours:	5:00 am – 11:00 am Monday through Friday
Shoulder-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1 The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2 The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 XXXX.

3 The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

ADJUSTMENTS (cont)

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

The contract period for all customers receiving service under this rate schedule will be one (1) year at the Company's option.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, which contains provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

RATE SCHEDULE GS-SCHOOLS L
GENERAL SERVICE (400 kW+)
TIME OF USE
ELEMENTARY AND SECONDARY SCHOOLS

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to Standard Offer electric service for private and public elementary and secondary schools (K-12) whose average monthly maximum demand is greater than 400 kW and less than 3,000 kW per month.

The Company will place the Customer on the applicable Rate Schedule GS-SCHOOLS M or GS-SCHOOLS L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination. The Company may also place the Customer on the Applicable Rate Schedule during the year, if the Customer has experienced a significant and permanent change in load as determined by the Company. Such placement will be based on available information.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.3 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services. Availability of this rate is subject to the availability of required metering equipment and completion of necessary enhancements to the Company's billing system

This schedule is not applicable to breakdown, standby, supplemental, or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP.

Service under this schedule is generally provided at secondary voltage; primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates, plus any adjustments incorporated in this rate schedule:

Basic Service Charge:

For service through Self-Contained Meters:	$ 0.658	per day, or
For service through Instrument-Rated Meters:	$ 1.328	per day, or
For service at Primary Voltage:	$ 3.477	per day, or
For service at Transmission Voltage:	$ 26.855	per day

RATES (cont)

Demand Charge:

Secondary Service:	$ 8.241	per kW for the first 100 kW, plus
	$ 3.601	per kW for all additional kW, or
Primary Service:	$ 7.521	per kW for the first 100 kW, plus
	$ 2.885	per kW for all additional kW, or
Transmission Service:	$ 5.498	per kW for the first 100 kW, plus
	$ 0.857	per kW for all additional kW

Energy Charge:

June – August Billing Cycles (Summer Peak)
$ 0.15822 per kWh during On-Peak hours, plus $ 0.1172 per kWh during Shoulder-Peak hours, plus $ 0.06333 per kWh during Off-Peak hours

May, September, and October Billing Cycles (Summer Shoulder)	November – April Billing Cycles (Winter)
$ 0.13663 per kWh during On-Peak hours, plus $ 0.10121 per kWh during Shoulder-Peak hours, plus $ 0.05469 per kWh during Off-Peak hours	$ 0.10556 per kWh during On-Peak hours, plus $ 0.07819 per kWh during Shoulder-Peak hours, plus $ 0.04225 per kWh during Off-Peak hours

POWER FACTOR

The customer deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. Service voltage levels at 69 kV or above shall maintain a power factor of ± 95% at all times. In situations where Company suspects that a customer's load has a non-confirming power factor, Company may install at its cost, the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a non-conforming power factor, or other detrimental conditions shall be required to remedy problems, or pay for facilities/equipment that Company must install on its system to correct for problems caused by the customer's load. Until such time as the customer remedies the problem to Company satisfaction, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

DETERMINATION OF KW

For billing purposes, including determination of Monthly Maximum Demands, the kW used in this rate schedule shall be based on the average kW supplied during the 15-minute period of maximum use during the month as determined from readings of the Company's meter.

DETERMINATION OF KW (cont)

For the purpose of placement on this rate, the Average Monthly Maximum Demand shall equal the average of the Monthly Maximum Demands for the May through October billing cycles, as determined by the Company. If the Monthly Maximum Demands are not available for all six May through October billing cycles, the Average Monthly Maximum Demand will be based on the available information. For a new customer, the initial Average Monthly Maximum Demand will be based on the estimated maximum kW provided by the Customer and approved by the Company.

TIME PERIODS

Time periods applicable to usage under this rate schedule are as follows:

Summer Peak (June - August)

On-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Shoulder-Peak hours:	11:00 am – 3:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Summer Shoulder (May, September and October)

On-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Shoulder-Peak hours:	11:00 am – 3:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Winter (November - April)

On-Peak hours:	5:00 am – 11:00 am Monday through Friday
Shoulder-Peak hours:	3:00 pm – 8:00 pm Monday through Friday
Off-Peak hours:	All remaining hours

Mountain Standard Time shall be used in the application of this rate schedule.

ADJUSTMENTS

1 The bill is subject to the Renewable Energy Standard as set forth in the Company's Adjustment Schedule REAC-1 pursuant to Arizona Corporation Commission Decision No. 70313.

2 The bill is subject to the Power Supply Adjustment factor as set forth in the Company's Adjustment Schedule PSA-1 pursuant to Arizona Corporation Commission Decision No. 67744, Arizona Corporation Commission Decision No. 69663, Arizona Corporation Commission Decision No. 71448 and XXXX.

3 The bill is subject to the Transmission Cost Adjustment factor as set forth in the Company's Adjustment Schedule TCA-1 pursuant to Arizona Corporation Commission Decision No. 67744 and XXXX.

4. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge as set forth in the Company's Adjustment Schedule RCDAC-1 pursuant to Arizona Corporation Commission Decision No. 67744.

5. The bill is subject to the Demand Side Management Adjustment charge as set forth in the Company's Adjustment Schedule DSMAC-1 pursuant to Arizona Corporation Commission Decision No. 67744 and Arizona Corporation Commission Decision No. 71448.

ADJUSTMENTS (cont)

6. The bill is subject to the Efficiency and Infrustructure Account Adjustment charge as set forth in the Company's Adjustment Schedule EIA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

7. The bill is subject to the Environmental and Reliability Account as set forth in the Company's Adjustment Schedule ERA-1 pursuant to Arizona Corporation Commission Decision No. xxxxx.

8. The bill is subject to 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 APS 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.

CONTRACT PERIOD

The contract period for all customers receiving service under this rate schedule will be one (1) year at the Company's option.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, which contains provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

SCHEDULE EPR-2
CLASSIFIED SERVICE
PURCHASE RATES FOR QUALIFIED FACILITIES
100 KW OR LESS FOR PARTIAL REQUIREMENTS

AVAILABILITY

This rate schedule is available in all territory served by the Company.

APPLICATION

This rate schedule is applicable to all cogeneration and small power production facilities with a nameplate continuous AC output power rating of 100 kW or less where the facility's generator(s) and load are located at the same premise and that otherwise meet qualifying status pursuant to Arizona Corporation Commission's Decision No. 52345 on cogeneration and small power production facilities. Applicable only to Qualifying Facilities electing to configure their systems as to require partial requirements service from the Company in order to meet their electric requirements.

TYPE OF SERVICE

Electric sales to the Company must be single or three phase, 60 Hertz, at one standard voltage as may be selected by the customer (subject to availability at the premises). The Qualifying Facility will have the option to sell energy to the Company at a voltage level different than that for purchases from the Company; however, the Qualifying Facility will be responsible for all incremental costs incurred to accommodate such an arrangement.

PAYMENT FOR PURCHASES FROM AND SALES TO THE CUSTOMER

Power sales and special services supplied by the Company to the customer in order to meet its supplemental or interruptible electric requirements will be priced at the applicable retail rate or rates.

The Company will pay the customer for any energy purchased as calculated on the standard purchase rate (see below).

MONTHLY PURCHASE RATE FOR EXCESS GENERATION

For customers with a 9 a.m. to 9 p.m. on-peak rate:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1/]	Off-Peak[2/]	On-Peak[1/]	Off-Peak[2/]
Summer Billing Cycles (May - October)	4.236	3.734	5.447	3.957
Winter Billing Cycles (November - April)	3.432	3.622	3.432	3.622

[1/] On-Peak Periods: 9 a.m. to 9 p.m., weekdays or as reflected in the customer's otherwise applicable retail rate schedule

[2/] Off-Peak Periods: All other hours

These rates are based on the Company's estimated avoided energy costs and will be updated annually.

For customers with a 12 p.m. to 7 p.m. on-peak rate:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1/]	Off-Peak[2/]	On-Peak[1/]	Off-Peak[2/]
Summer Billing Cycles (May - October)	4.473	3.766	6.548	3.947
Winter Billing Cycles (November - April)	3.224	3.641	3.224	3.641

[1/] On-Peak Periods: 12 p.m. to 7 p.m., weekdays or as reflected in the customer's otherwise applicable retail rate schedule

[2/] Off-Peak Periods: All other hours

These rates are based on the Company's estimated avoided energy costs and will be updated annually.

For customers with an 11 a.m. to 9 p.m. on-peak rate:

	Cents per kWh			
	Non-Firm Power		Firm Power	
	On-Peak[1/]	Off-Peak[2/]	On-Peak[1/]	Off-Peak[2/]
Summer Billing Cycles (May - October)	4.405	3.705	5.857	3.910
Winter Billing Cycles (November - April)	3.361	3.636	3.361	3.636

[1/] On-Peak Periods: 11 a.m. to 9 p.m., weekdays or as reflected in the customer's otherwise applicable retail rate schedule

[2/] Off-Peak Periods: All other hours

These rates are based on the Company's estimated avoided energy costs and will be updated annually.

For residential customers served under a standard (non time-of-use) rate, the monthly purchase rate will equal the rate for customers served on a 12 p.m. to 7 p.m. on-peak rate. For all other customers served under a standard rate, the monthly purchase rate will equal the rate for customers served on an 11 a.m. to 9 p.m on-peak rate.

CONTRACT PERIOD

As provided for in any Supply /Purchase Agreement.

DEFINITIONS

1. Partial Requirements Service - Electric service provided to a customer that has an interconnected generation system configuration whereby the output from its electric generator(s) first supplies its own electric requirements and any Excess Generation (over and above its own requirements at any point in time) is then provided to the Company. The Company supplies the customer's supplemental electric requirements (those not met by their own generation facilities). This configuration may also be referred to as the "parallel mode" of operation.

2. Excess Generation – Equals the customer's generation (kWh) in excess of their load at any point in time as metered by the Company. Excess Generation is computed for on-peak and off-peak billing periods.

3. Special Service(s) - The electric service(s) specified in this section that will be provided by the Company in addition to or in lieu of normal service(s).

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

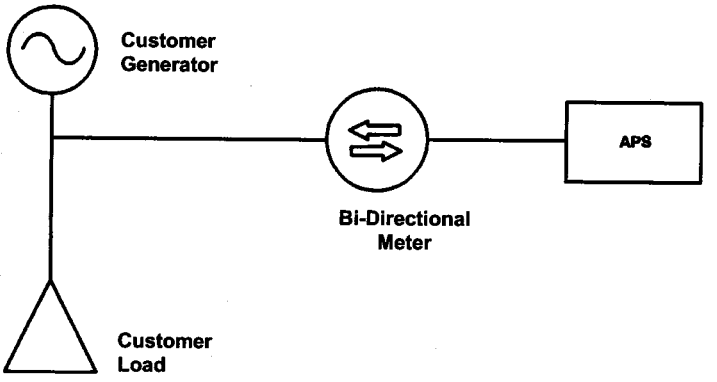
5. Firm Power - Power available, upon demand, at all times (except for forced outages) during the period covered by the Purchase Agreement from the customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

6. Time Periods - Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services, Schedule 2, Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities, and the Company's Interconnection requirements for Distributed Generation. This schedule has provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer interconnection or Supply/Purchase agreement.

METERING CONFIGURATION



RATE SCHEDULE EPR-6 (NET METERING)
CLASSIFIED SERVICE
RATES FOR RENEWABLE RESOURCE FACILITIES FOR PARTIAL REQUIREMENTS

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is offered to customers with metered kWh usage with a Net Metering Facility that uses Renewable Resources, a fuel cell, or combined heat and power (CHP) to produce electricity. Definitions are pursuant to A.A.C. R14-2-2302. Participation under this schedule is subject to availability of enhanced metering and billing system upgrades.

DEFINITIONS

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

2. Customer Supply – Energy (kWh) from a customer-owned Net Metering Facility that exceeds the customer's load at a point in time and is fed back into the Company's electric system, as metered by the Company.

3. Customer Purchase – Energy (kWh) that is provided from the Company to the customer to serve the load that is not being served by a customer-owned Net Metering Facility, as metered by the Company.

4. Excess Generation – Equals the Customer Supply (kWh) less the Customer Purchase (kWh) over a monthly billing period. For time-of-use rates the Excess Generation corresponding to the on and off peak periods is computed for on-peak and off-peak periods over the monthly billing period. (Not to be less than zero).

5. Fuel Cell – A device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. For purposes of this rate schedule, the source of the chemical reaction must be derived from Renewable Resources.

6. Net Metering Facility – A facility for the production of electricity that:
   a) Is operated by or on behalf of a Net Metering customer and is located on the net metering customer's premises and;
   b) Is intended primarily to provide part or all of the net metering customer's requirement for electricity and;
   c) Uses Renewable Resources, a fuel cell, or CHP to generate electricity and;
   d) Has a generating capacity less than or equal to 125% of the net metering customer's total connected load, or in the absence of customer load data, capacity less than or equal to the customer's electric service drop capacity and;
   e) Is interconnected with and can operate in parallel and in phase with the Company's existing distribution system.

DEFINITIONS (cont)

7. Partial Requirements Service – Electric service provided to a customer that has an interconnected Net Metering Facility whereby the output from its electric generator(s) first supplies its own electric requirements and any excess energy (over and above its own requirements at any point in time) is then provided to the Company. The Company supplies the customer's supplemental electric requirements (those not met by their own generation facilities). This configuration may also be referred to as the "parallel mode" of operation.

8. Renewable Resources – Natural resources that can be replenished by natural processes, including; biogas, biomass, geothermal, hydroelectric, solar, or wind.

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

10. Firm Power - Power available, upon demand, at all times (except for forced outages) during the period covered by the Purchase Agreement from the customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

11. Standard Retail Rate Schedule – Any of the Company's retail rate schedules with metered kWh charges.

12. Time Periods - Mountain Standard Time shall be used in the application of this rate schedule. Because of potential differences of the timing devices, there may be a variation of up to 15 minutes in timing for the pricing periods. On-peak and off-peak time periods will be determined by the applicable Standard Retail Rate Schedule.

TYPE OF SERVICE

Electric sales to the Company must be single phase or three phase, 60 Hertz, at one standard voltage as may be selected by customer (subject to availability at the premises).

BILLING

A. During the billing period for:

1. Customer Purchases in excess of Customer Supply:

   Company shall bill the customer for the net kWh supplied by the Company in accordance with the applicable Standard Retail Rate Schedule.

2. Customer Supply in excess of Customer Purchases (Excess Generation):

   Company shall credit the customer the Excess Generation kWh in subsequent billing periods.

B. For customers taking service under time-of-use rates, Customer Supply and Customer Purchases will be segmented by on-peak and off-peak periods. Excess Generation kWh credits will be applied to the time-of-use periods in which the kWh were generated by the customer.

C. Basic Service Charges and Demand charges (either metered or contract) will continue to apply in full.

BILLING (cont)

D. For the last billing period of each calendar year or for the last billing period at the time the customer discontinues taking service under this rate schedule;

The Company shall issue a billing credit to the customer for any remaining Excess Generation balance. In the event the customer's electric service is terminated, after applying a billing credit for any Excess Generation up to the amount the customers owes the Company, the Company shall issue a check for the remaining value of the Excess Generation balance. The payment or credit will be determined at the Company's annual avoided costs (Annual Purchase Rate), which are updated annually and as specified below:

	Non-Firm			Firm		
	On-peak	Off-peak	Total	On-peak	Off-peak	Total
Annual Purchase Rates (¢/kWh)	6.590	5.963	6.187	7.714	6.172	6.722

CONTRACT PERIOD

Any applicable contract period(s) will be set forth in an Agreement between the customer and the Company.

METERING

Customers served under this rate schedule will require a bi-directional meter that will register and accumulate the net electrical requirements of the customer. The Company will install such a meter at the customer's Net Metering Facility if proper metering is not already present. The incremental metering costs for bidirectional metering and the facility meter will be incurred by the Company. A bidirectional meter may not be required if the generating capacity of the Net Metering Facility is less than 10% of the customer's lowest billing demand over the previous 12 months, or as otherwise determined by the Company through available information, and if the customer agrees that they do not intend to net any Excess Generation on their monthly bill.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1 Terms and Conditions for Standard Offer and Direct Access Services, Schedule 2 Terms and Conditions for Energy Purchases from Qualified Cogeneration or Small Power Production Facilities, Schedule 3 Conditions Governing Extensions of Electrical Distribution Lines and Services, and the Company's Interconnection Requirements for Distributed Generation.

ADJUSTMENT SCHEDULE GPS-1
GREEN POWER BLOCK SCHEDULE

APPLICATION

Adjustment Schedule GPS-1 ("GPS-1") shall be applied to Standard Offer customers who wish to purchase electricity generated from renewable sources for their homes and/or businesses. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge.

Electricity from renewable sources shall be referred to herein as "Green Power". Green Power may be:

1. Company-owned generation using eligible renewable resources as defined by the Renewable Energy Standard rules (A.A.C. R14-2-1802 and successors).
2. Generation not owned by the Company, but owned by another party for which the Company has contracted using eligible renewable resources as defined by the Renewable Energy Standard rules (A.A.C. R14-2-1802 and successors).

TYPE OF SERVICE

The Company will offer electricity generated from renewable resources delivered through the Company's electric distribution system.

Effective October 1, 2009 the Company, at its discretion, may limit the number of kWh blocks sold to any one customer to no more than five percent of total Green Power procured for service under schedules GPS-1, GPS-2, and GPS3.

The customer shall subscribe for a specific number of blocks of electricity generated from renewable resources. Each block shall equal 100 kWh per month. The monthly charge is based upon the number of blocks subscribed for by the customer.

The Company shall limit the participation in GPS-1 based on the Green Power available to provide service under this rate schedule.

Customers are required to subscribe for a minimum of one year, but can commit to subscribe for a longer period at their discretion. Charges under this schedule will be adjusted annually with Commission approval. Customers may cancel GPS-1 service if the charges increase during the one year or longer commitment period.

GPS-1 may not be used in conjunction with rate schedule GPS-2.

SERVICE CHARGES

Service under this rate schedule shall be billed the Green Power Block rate of $0.40 per month for each 100 kWh block of Green Power. This charge is based on the Green Power Premium rate of $0.004 per kWh of Green Power times 100 kWh.

ADJUSTMENT SCHEDULE GPS-2
GREEN POWER PERCENT SCHEDULE

APPLICATION

Adjustment Schedule GPS-2 ("GPS-2") shall be applied to Standard Offer customers who wish to purchase electricity generated from renewable sources for their homes and/or businesses. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge.

Electricity from renewable sources shall be referred to herein as "Green Power". Green Power may be:

1. Company-owned generation using eligible renewable resources as defined by the Renewable Energy Standard rules (A.A.C. R14-2-1802 and successors).
2. Generation not owned by the Company, but owned by another party for which the Company has contracted using eligible renewable resources as defined by the Renewable Energy Standard rules (A.A.C. R14-2-1802 and successors).

TYPE OF SERVICE

The Company will offer Green Power through the Company's electric distribution system.

Effective October 1, 2009 the Company, at its discretion, may limit the kWh sold to any one customer to no more than five percent of total Green Power procured for service under schedules GPS-1, GPS-2, and GPS-3.The Company shall limit the participation in GPS-2 based on the Green Power available to provide service under this rate schedule.

Customers are required to subscribe for a minimum of one year, but can commit to subscribe for a longer period at their discretion. Charges under this schedule will be adjusted annually with Commission approval. Customers may cancel GPS-2 service if the charges increase during the one year or longer commitment period.

GPS-2 may not be used in conjunction with rate schedule GPS-1.

SERVICE CHARGES

Four options are available. The charges hereunder represent charges to be added to energy charges ($/kWh basis) under the customer's applicable rate schedule and applied to the customer's total monthly kWh (including non-Green Power kWh, if any) supplied by the Company. The charges are based on the Green Power Premium rate of $0.004 per kWh of Green Power.

A. Green Power shall account for 100.0% of the total monthly kWh supplied by the Company.
Additional Charge per kWh: $0.004

B. Green Power shall account for 50.0% of the total monthly kWh supplied by the Company.
Additional Charge per kWh: $0.002

C. Green Power shall account for 35.0% of the total monthly kWh supplied by the Company.
Additional Charge per kWh: $0.0014

D. Green Power shall account for 10.0% of the total monthly kWh supplied by the Company. This option is not available to residential customers.
Additional Charge per kWh: $0.0004

ADJUSTMENT SCHEDULE GPS-3
GREEN POWER BLOCK SCHEDULE
FOR SPECIAL EVENTS

APPLICATION

Adjustment Schedule GPS-3 ("GPS-3") shall be applied to Standard Offer customers who wish to purchase electricity generated from renewable sources for their Green Event. A Green Event is temporary in nature and includes, but is not limited to, concerts, sporting events, festivals, fairs, which can be held over single or contiguous multiple days at single or multiple sites. All provisions of the customer's current applicable rate schedule will apply in addition to this surcharge. For purposes of this adjustment, the total Green Power kWh will apply in the month they are purchased.

Electricity from renewable sources shall be referred to herein as "Green Power." Green Power may be:

1. Company-owned generation using eligible renewable resources as defined by the Renewable Energy Standard rules (A.A.C. R14-2-1802 and successors).
2. Generation not owned by the Company, but owned by another party for which the Company has contracted using eligible renewable resources as defined by the Renewable Energy Standard rules (A.A.C. R14-2-1802 and successors).

TYPE OF SERVICE

The Company will offer electricity generated from renewable resources delivered through the Company's electric distribution system.

The Company shall limit the participation in GPS-3 based on the Green Power available to provide service under this rate schedule.

The Company, at its discretion, may limit the number of kWh blocks sold to any one customer to no more than five percent of total Green Power procured for service under schedules GPS-1, GPS-2 and GPS-3.

Each block shall equal 100 kWh subscribed for by the customer.

Charges under this schedule will be adjusted annually with Commission approval.

Because rate schedule GPS-3 is for a temporary event, Section 3.3 of APS' Schedule 1 shall not apply.

SERVICE CHARGES

Service under this rate schedule shall be billed the Green Power Block rate of $0.40 for each 100 kWh block of Green Power for the duration of the special event. This charge is based on the Green Power Premium rate of $0.004 per kWh of Green Power times 100 kWh. Minimum purchase shall be $500.00 per transaction.

RATE SCHEDULE E-56 R
CLASSIFIED SERVICE
PARTIAL REQUIREMENTS

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served and when all applicable provisions described herein have been met.

APPLICATION

Customers taking service under this rate schedule will be served in accordance with the attached template E-56 R Electric Supply/Purchase Agreement between Company and Customer, which is incorporated herein by reference. This rate schedule is applicable to customers having solar/photovoltaic generation equipment with a nameplate service continuous rating of greater than 100 kW capable of supplying all or a portion of its power requirements. Direct access customers are not eligible for service under this rate schedule.

METERING

The Company will install, at the customer's expense, a bi-directional meter at the point of delivery to the customer (Supply Meter) and meter(s) at the point(s) of output from each of the customer's generators (Generator Meter). All meters will record integrated demand and energy on the same 15- minute interval basis as specified by the Company.

CONTRACT PERIOD

As provided in the E-56 R Electric Supply/Purchase Agreement between Company and Customer.

TERMS AND CONDITIONS

Customer must enter into an Interconnection Agreement and the E-56 R Electric Supply/Purchase Agreement to establish all pertinent details related to interconnection and other required service standards. APS will file the executed Electric Supply/Purchase Agreement in compliance with A.C.C. Decision No. 70130.

RATE SCHEDULE SOLAR-2
CLASSIFIED SERVICE
INDIVIDUAL SOLAR ELECTRIC SERVICE

THIS RATE IS CANCELED EFFECTIVE XXXXX PER A.C.C. DECISION NO. XXXXX.

RATE SCHEDULE SOLAR-3
CLASSIFIED SERVICE
SOLAR POWER PILOT PROGRAM

THIS RATE IS CANCELED EFFECTIVE XXXXX PER A.C.C. DECISION NO. XXXXX.

RATE SCHEDULE CMPW-01
COMMUNITY POWER – FLAGSTAFF SANDVIG 04
PILOT RIDER RATE

AVAILIBILITY

This pilot rate schedule is available to customers that are located within the Community Power boundaries of the limited geographical area in Flagstaff, Arizona served by the Sandvig 04 circuit feeder as defined by the Company and approved by the Arizona Corporation Commission ("ACC") in Decision No. 71646.

APPLICATION

This pilot rate schedule shall apply to retail Standard Offer customers served under rate schedules E-12, ET-2, E-32 S, E-32 M, E-32-L, E-32TOU S, E-32TOU M, and E-32TOU L or their successor rate schedules as approved by the ACC. All provisions of the customer's current applicable rate schedule will apply in addition to the charges and credits defined within this rate schedule. Rate Schedule CMPW-01 may not be used in conjunction with any of the Company's partial requirements rate schedules.

In addition, to be eligible for this rate schedule, the customer must meet the program requirements to participate in the Community Power Program in Flagstaff, Arizona including but not limited to (1) granting the Company an easement to install, own, operate and maintain a solar photovoltaic system on customer's premises and (2) meeting the technical requirements for the customer's premises. The rate and terms and conditions of this rate schedule are applicable only to this pilot rate.

TERM

This rate schedule shall remain in effect for a period of twenty years from its effective date unless cancelled or modified by the ACC prior to such date. Customers can discontinue participation in this rate schedule at any time without penalty.

SOLAR OPTIONS

Residential Options: For residential customers there are three photovoltaic equipment size options for service under this rate schedule, with nominal kW-DC ratings approximately equal to 2kW, 3kW, and 4kW.

General Service Options: Photovoltaic equipment size options available to general service customers under this rate schedule range from 50 to 250 kW.

DETERMINATION OF SOLAR ENERGY

The Solar Energy, which is the nominal expected monthly kWh output from the photovoltaic solar installation over time, shall be derived by multiplying the kW-DC rating of the photovoltaic installation by an average monthly production factor (kWh-AC per kW-DC), as determined by the Company. The monthly production factor for Residential Options is 105 kWh-AC per kW-DC and for General Service Options it is 90 kWh-AC per kW-DC.

RATES

The customer's monthly bill shall be calculated in accordance with their current applicable rate schedule except that:

(1) The monthly bill will include a Solar Charge, which is the Solar Energy multiplied by the per kWh charges listed below. The Solar Charge is a fixed monthly amount for the term of this rate schedule.

Solar Option	Applicable Retail Rate Schedule	Solar Charge per kWh
Residential	E-12	$0.11242
Residential	ET-2	$0.13480
General Service	E-32 S, E-32 M, E-32 L	$0.09293
General Service	E-32TOU S, E-32TOU M, E-32TOU L	$0.05855

(2) The monthly bill will be based on the Customer's total metered usage net of the Solar Energy applied to all unbundled kWh charges in the customer's current applicable rate schedule, where the netted kWh shall not be less than zero. The netting shall be applied as follows:

- ET-2, E-32TOU S, E-32TOU M, E-32TOU L - 50% of Solar Energy shall be netted from on-peak kWh, 50% from off-peak kWh. If the net kWh is less than zero for either the on-peak or off-peak period, the remaining kWh shall be netted from the other time period, where the netted amount shall not be less than zero.

- E-12 - Solar Energy shall be netted from the second tier kWh charges. If the netted kWh is less than zero the remaining kWh shall be netted against the first tier of kWh charges, where the netted amount shall not be less than zero.

- E-32 S, E-32 M, E-32 L - Solar Energy shall be netted from first tier kWh charges. If the netted kWh is less than zero the remaining kWh shall be netted against the second tier of kWh charges, where the netted amount shall not be less than zero.

- All kWh adjustment charges will be calculated on total metered kWh and then the bill will be credited for the Solar Energy multiplied by those charges.

- Discount levels for the Energy Support Program and Medical Care Equipment under rate schedules E-3 and E-4 will be based on the Customer's total metered usage.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Terms and Conditions of the customer's parent rate schedule. This schedule has provisions that may affect the customer's bill.

RATE SCHEDULE RSSP
RURAL SCHOOLS SOLAR PROGRAM
RIDER RATE

AVAILIBILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served. The rate schedule was approved by the Arizona Corporation Commission ("ACC") in Decision Nos. 72022 and 72174.

APPLICATION

This rate schedule shall apply to retail Standard Offer electric service for eligible public elementary and secondary schools (K-12), including charter schools served under rate schedules E-32 S, E-32 M, E-32-L, E-32TOU S, E-32TOU M, E-32TOU L, GS-SCHOOLS M, and GS-SCHOOLS L or their successor rate schedules as approved by the ACC. All provisions of the customer's current applicable rate schedule will apply in addition to the charges and credits defined within this rate schedule. Rate Schedule RSSP may not be used in conjunction with any of the Company's partial requirements rate schedules.

Eligibility shall be determined by the Company based on the following requirements:

(1) The customer must be an economically challenged school as defined as having a per pupil available bonding capacity of $8,000 or less and 60% or more of its students participating in free or reduced lunch program;
(2) The customer must be located in a designated rural area as classified by the U.S. Census Bureau;
(3) The customer must provide an alternate solar proposal from a third-party not affiliated with APS; and
(4) The customer must be a participant in the Rural Schools Solar Program and therefore meet the program requirements including but not limited to (a) granting the Company an easement to install, own, operate and maintain a solar photovoltaic system on customer's premises and (b) meeting the technical requirements for the customer's premises.

TERM

The Solar Charge herein shall remain in effect for 20 years from the customer's effective date. Customers can discontinue participation in this rate schedule at any time without penalty.

SOLAR OPTIONS

The solar photovoltaic equipment size options available under this rate schedule shall be less than or equal to 350 kW-DC of nominal rated capacity for customers with a K-8 school or facilities totaling 75,000 square feet or less at the site where the solar equipment is installed. For customers with a high school or facilities totaling more than 75,000 square feet the solar equipment shall be less than or equal to 550 kW-DC.

In addition, the solar equipment capacity (kW-AC) shall not be greater than 125% of the customer's connected load (kW-AC) as determined in accordance to rate schedule EPR-6 and A.A.C. R14-2-2302, nor shall the Solar Energy be more than 100% of the customer's metered kWh for the previous 12 months. Both of these limitations shall be determined at the time of initial qualification for the rate.

DETERMINATION OF SOLAR ENERGY

The Solar Energy, which is the nominal expected monthly kWh output from the photovoltaic solar equipment over time, shall be derived by multiplying the kW-DC rating of the photovoltaic equipment by an average monthly production factor (kWh-AC per kW-DC), as determined by the Company. The monthly production factor is 90 kWh-AC per kW-DC. For billing purposes, the Solar Energy in any month shall not exceed the customer's metered kWh used in computing the monthly bill. For totalized metering service provided under Service Schedule 4, the Solar Energy shall not exceed the metered kWh from the single service entrance section where the solar facility is installed.

RATES

The customer's monthly bill shall be calculated in accordance with their current applicable rate schedule except that:

(1) The monthly bill will include a Solar Charge, which is the Solar Energy multiplied by the per kWh charges listed below.

Applicable Retail Rate Schedule	Solar Charge per kWh
E-32 S, E-32 M, E-32 L	$0.09293
E-32TOU S, E-32TOU M, E-32TOU L	$0.05855
GS-SCHOOLS M, GS-SCHOOLS L	$0.07158

(2) The monthly bill will be based on the Customer's total metered usage net of the Solar Energy applied to all unbundled kWh charges and adjustments in the customer's current applicable rate schedule, where the netted kWh shall not be less than zero. The netting shall be applied as follows:

- E-32TOU S, E-32TOU M, E-32TOU L - 50% of Solar Energy shall be netted from on-peak kWh, 50% from off-peak kWh. If the net kWh is less than zero for either the on-peak or off-peak period, the remaining kWh shall be netted from the other time period, where the netted amount shall not be less than zero.

- E-32 S, E-32 M, E-32 L - Solar Energy shall be netted from first tier kWh charges. If the netted kWh is less than zero the remaining kWh shall be netted against the second tier of kWh charges, where the netted amount shall not be less than zero.

- GS-SCHOOLS M, GS-SCHOOLS L – Solar Energy shall be netted from the on-peak, shoulder-peak and off-peak kWh according to the following allocation:

Season	Time Period		
	On-Peak	Shoulder-Peak	Off-Peak
Summer Peak (Jun-Aug)	15.0%	35.0%	50.0%
Summer Shoulder (May, Sep & Oct)	15.0%	35.0%	50.0%
Winter (Nov-Apr)	20.0%	10.0%	70.0%

If the net kWh is less than zero in any period, the remaining kWh shall be applied first to the on-peak, and then the shoulder-peak, and the off-peak period if necessary, where the resulting kWh in any period shall not be less than zero.

- Any reductions to the monthly kWh billed under Schedule RES and Schedule EIS due to participation in green power schedules GPS-1, GPS-2, GPS-3 and Solar-3 will be capped at the customer's total metered kWh net of the Solar Energy provided in Schedule RSSP.

- The Solar Energy shall be netted against the metered kWh from the single service entrance section where the solar facility is installed and shall not be netted against metered kWh from any other metered kWh at other points of delivery at the same customer site or other sites.

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Terms and Conditions of the customer's parent rate schedule. This schedule has provisions that may affect the customer's bill.

Adjustments

ADJUSTMENT SCHEDULE DSMAC-1
DEMAND SIDE MANAGEMENT COST ADJUSTMENT

APPLICATION

The Demand Side Management Adjustment Charge ("DSMAC") shall be applied monthly to every metered and/or non-metered retail Standard Offer or Direct Access service. All provisions of the customer's currently applicable rate schedule will apply in addition to this adjustment charge. The DSMAC is applied to Standard Offer or Direct Access customer's bills as monthly charge to recover the cost of Commission approved demand side management programs above those costs included in base rates. The DSMAC will be changed in billing cycle 1 of the March revenue month and will not be prorated. The DSMAC and the RES adjustors may be combined on the customer's bill and appear on the "Environmental Benefits Surcharge" line. Details of how the DSMAC is derived and administered can be found in the Demand Side Management Adjustment Charge Plan for Administration.

RATE

The charge shall be calculated at the following rate:

For all residential customers and general service customers whose billing does not include demand charges:

All kWh	$0.002717	per kWh

For general service customers whose billing includes demand charges:

All metered kW	$0.9685	per kW

SELF DIRECTION

Self direction of DSM charges collected through base rates and Adjustment Schedule DSMAC-1 shall be available for customers who use more than 40 million kWh per year, based on an aggregation of the usage for all the customer's accounts for the January through December billing months in the year the request for self direction is made.

Qualifying customers who elect to self direct their DSM charges must notify APS on or before December 1st in each year that they wish to self direct. Upon such notification, and verification of eligibility by APS, 85% of the customer's DSM charges paid over the January through December billing months in the election year will be reserved for tracking purposes for the customer's eligible energy efficiency project(s) to be completed within two years. The remaining 15% will be retained to cover the self direction program administration, management and verification, measurement and evaluation, and low-income program costs.

Customers who elect to self direct must continue to pay the DSM charges in base rates and Adjustment Schedule DSMAC-1.

Self direction shall be provided in accordance with the Self Direction Provisions approved in Arizona Corporation Commission (Commission) Decision No. 71448, Attachment C to the Settlement Agreement as modified from time to time with Commission approval.

Self direction amounts shall be the DSMAC-1charges billed over the election year plus the DSM charges recovered in base rates. The latter shall be calculated by multiplying the kWh billed for the System Benefits Charge in the customer's current applicable rate schedule multiplied by $0.000359 per kWh.

ADJUSTMENT SCHEDULE REAC-1
RENEWABLE ENERGY STANDARD

APPLICATION

The Renewable Energy Standard Adjustment Schedule ("REAC") shall apply to all retail Standard Offer or Direct Access service. All provisions of the customer's current applicable rate schedule will apply in addition to adjustment schedule REAC-1. This schedule shall recover the revenue requirements from the Renewable Energy Standard that are not other wise recoverd in base rates. The kWh charge and monthly surcharge limits shall be revised annually, as necessary, as approved by the Arizona Corporation Comission ("Commission"). Any new charges and surcharge limits will be applied in billing cycle 1 in the January revenue month, or as otherwise ordered by the Commission, and will not be prorated. Details regarding the administration of this Adjustor can be found in A.A.C. R14-2-1808. Adjustment schedules REAC-1 and DSMAC-1 may be combined on the customer's bill and shown on the "Environmental Benefits Surcharge" line.

RATES

The bill shall be calculated at the following rates:

All kWh	$0.010132	per kWh

SURCHARGE LIMITS

The monthly total of the Renewable Energy Standard Adjustment Charge shall not exceed the following limits:

Residential Customers	$4.05	per service per month
Non-residential Customers	$150.53	per service per month
Non-residential Customers with demand of 3,000 kW or higher per month for three consecutive months	$451.60	per service per month

ADJUSTMENT SCHEDULE SDR
SELF-DIRECTED RENEWABLE RESOURCES

APPLICATION

Pursuant to Arizona Administrative Code ("A.A.C.") R14-2-1809, Adjustment Schedule Self-Directed Renewable Resources ("SDR") shall apply to any retail Standard Offer or Direct Access customers who, as a result of regular Company monthly billings, pay $25,000 or more during a calendar year to the Company under Adjustment Schedule RES, Renewable Energy Standard ("RES"), which was approved by the Arizona Corporation Commission ("ACC") in Decision No. 70313.

ELIGIBILITY REQUIREMENTS

1. Funding Eligibility:

   a. The customer is eligible to receive funds pursuant to this schedule if the total of all RES related payments made to the Company for the customer's service account or accounts, individually or collectively, total $25,000 or more in any one calendar year (January – December).

   b. Funds collected from the customer in any one year (the "Payment Year") will be available to the customer for self-directed projects in the following year (the "Funding Year"). Funds received during the Funding Year will not exceed payments collected by the Company in the Payment Year. In addition, if the customer has facilities in multiple service territories, only those payments collected by the Company are eligible for SDR funding.

   c. Customers requesting funds for self-directed projects must declare their intention by applying in writing to the Company on or before March 31 of the Payment Year. The application must include a description of the proposed project and its expected cost.

   d. The customer shall provide at least half of the funds necessary to complete the proposed project, as required by A.A.C. R14-2-1809.B.

2. Project Eligibility:

   a. SDR funds obtained by the customer from the Company may only be used for projects physically located within the Company's service territory.

   b. Projects specified in the Company's Distributed Energy Administration Plan ("DEAP") are eligible for SDR funding. Self-direct requesting customers must request incentives no greater than the prescribed incentives specified in the DEAP. If the customer wishes to apply funds to a project not specified in the DEAP, the customer must submit documentation detailing project economics and funding requirements.

   c. Any project proposed by the customer must meet the requirements for a Distributed Renewable Energy Resource described in the ACC's Renewable Energy Standard Rules (A.A.C. R14-2-1802.B).

   d. For purposes of financing SDR projects, funds provided by the Company may be assigned to third parties. Such assignment will be at the customer's sole discretion. The Company assumes no liability for third-party assigned funds.

RENEWABLE ENERGY CREDITS

All Renewable Energy Credits derived from any project funded through this schedule, including generation and Extra Credit Multipliers, shall be applied to satisfy the Company's Annual Renewable Energy Requirement as provided for in A.A.C. R14-2-1809.C.

ADJUSTMENT SCHEDULE PSA-1
POWER SUPPLY ADJUSTMENT

APPLICATION

The Power Supply Adjustment ("PSA") shall apply to all retail electric rate schedules in accordance with their terms with the exception of E-36 XL, AG-1, and Direct Access service. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

RATES

The charges shall be calculated at the following rates:

PSA Historical Component		
All kWh	$(0.002642)	per kWh
PSA Forward Component		
All kWh	$(0.003016)	per kWh
PSA Transition Component		
All kWh	$0.000000	per kWh

ADJUSTMENT SCHEDULE RCDAC-1
RETURNING CUSTOMER DIRECT ACCESS CHARGE

APPLICATION

The Returning Customers Direct Access Charge ("RCDAC") shall apply to customers, or an aggregated group of customers, of 3 MW or greater who left Standard Offer or special contract service for competitive generation suppliers and desire to return to Standard Offer service. Customers that have been Direct Access customers since the orgination of their APS service that request Standard Offer service are considered to be returning customers. The RCDAC can only be applied if the customer(s) wants to return to Standard Offer service and the Company did not include their load in planned resource acquisitions. If APS is provided one year's advance notice of the customer's intent to return to Standard Offer service then they will not be assessed RCDAC. APS may create a special RCDAC in each individual case and require the customer(s) to enter into a service agreement that specifies the charge, its duration, and how it will be applied and collected. In situations where an aggregated group of customers wish to return, each customer from the group will be charged the same rate for the same duration and an Electric Service Agreement will be required from each customer. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

RATE

The charge will be identified in the Electric Service Agreement between the Customer and the Company and will be in addition to the Standard Offer service charges. The RCDAC will be based on the cost differential between the applicable Standard Offer rate generation component and the cost of the resources required to serve the returning customer(s). The costs associated with serving customers that are required to enter into RCDAC agreements will be kept separate from the retail power supply costs subject to recovery through the Power Supply Adjustment. The types of costs that will be used to develop the RCDAC are incremental Power Supply, Transmission, Ancillary Services and Metering costs as defined in the Returning Customer Direct Access Charge Plan for Administration. These costs will be amortized over an appropriate period to allow their timely recovery. In no event, however, will the RCDAC last longer than 12 months for any individual customer.

ADJUSTMENT SCHEDULE TCA-1
TRANSMISSION COST ADJUSTMENT

APPLICATION

The Transmission Cost Adjustment ("TCA") charge shall apply to all Standard Offer retail rate schedules. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

ANNUAL ADJUSTMENT

In accordance with A.C.C. Decision No. XXXXX, Adjustment Schedule TCA-1 shall recover the transmission costs in retail rates provided in the Company's Open Access Transmission Tariff, which are revised annually and filed with the Federal Energy Regulatory Commission. The annual revisions to Adjustment Schedule TCA-1 shall be filed with the A.C.C. by May 15th each year, and shall become effective June 1. The revised charges shall be effective on customer's bills beginning with June billing cycles and shall not be prorated.

RATE

The charge shall be applied as follows:

Customer Class	TCA Charge
Residential	$XXXXkWh
General Service 20 kW or less	$XXXX/kWh
General Service over 20 kW, under 3,000 kW	$XXXX/kW
General Service 3,000 kW and over	$XXXX/kW

ADJUSTMENT SCHEDULE EIS
ENVIRONMENTAL IMPROVEMENT SURCHARGE

THIS ADJUSTMENT SCHEDULE IS CANCELED PURSUANT TO A.C.C. DECISION NO. XXXX.

ADJUSTMENT SCHEDULE ERA-1
ENVIRONMENTAL AND RELIABILITY ACCOUNT

APPLICATION

The Envirnomental and Reliabity Account ("ERA") shall be applied monthly to all retail Standard Offer or Direct Access service, except for E-36XL. All provisions of the customer's currently applicable rate schedule will apply in addition to this adjustment charge. The ERA adjustment will be updated in billing cycle 1 of the April revenue month and will not be prorated. Details of how the adjustment is derived and administered can be found in the Envirnomental and Reliabity Account Plan of Administration approved by the ACC in Decision No. XXXXX.

RATE

The ERA charge will be applicable to the customer's total billed amount (which amount shall not be less than zero) including all other adjustors, except for the Efficiency and Infrastructure Account, excluding sales tax, transaction privilege tax, regulatory assessments, and franchise fees.

ERA Charge: X.X%

ADJUSTMENT SCHEDULE EIA-1
EFFICIENCY AND INFRASTRUCTURE ACCOUNT

APPLICATION

The Efficiency and Infrastructure Account ("EIA") shall be applied monthly to all retail Standard Offer or Direct Access service, except for E-30, E-36XL, E-47, E-58, E-59 and Contract 12. All provisions of the customer's currently applicable rate schedule will apply in addition to this adjustment charge. The EIA adjustment will be updated in billing cycle 1 of the March revenue month and will not be prorated. Details of how the adjustment is derived and administered can be found in the Efficiency and Infrastructure Account Plan of Administration approved by the ACC in Decision No. XXXXX.

RATE

The EIA charge will be applicable to the customer's total billed amount (which amount shall not be less than zero) including all other adjustors, except for the Environmental and Reliability Account, excluding sales tax, transaction privilege tax, regulatory assessments, and franchise fees.

EIA Charge: X.X%

Service Schedules

ARIZONA PUBLIC SERVICE COMPANY

Index to Rate Schedules

SERVICE SCHEDULES

	Schedule 1	Terms and Conditions for Standard Offer and Direct Access
UNCHANGED	Schedule 2	Terms and Conditions for Energy Purchases from Qualified Cogeneration and Small Power Production Facilities
UNCHANGED	Schedule 3	Conditions Governing Extensions of Electric Distribution Lines and Services
UNCHANGED	Schedule 4	Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service
UNCHANGED	Schedule 5	Guidelines for Electric Curtailment
UNCHANGED	Schedule 6	Interconnection Services and Fees for Non-FERC Wholesale Generation Facilities
UNCHANGED	Schedule 7	Electric Meter Testing and Maintenance Plan
UNCHANGED	Schedule 8	Bill Estimation
NEW	Schedule 9	Economic Development
UNCHANGED	Schedule 10	Terms and Conditions for Direct Access
UNCHANGED	Schedule 15	Conditions Governing the Providing of Specialized Metering
UNCHANGED	Schedule 16	Home Energy Information Pilot (Experimental)

Notes:

(1) Redline and final rate schedules have been provided for all rates, expect that redline rate schedules have not been provided for new rates or for rates that are unchanged in this rate case.

(2) Schedules marked FROZEN* were frozen to new customers at times noted on the individual schedule per Arizona Corporation Decision 71448.

(3) Unless otherwise noted, elements of rate schedule have been changed.

Schedule 1

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

The following TERMS AND CONDITIONS and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (Company), under the established rate or rates authorized by law and currently applicable at time of sale.

Definitions

a. Applicant means a person requesting the utility to supply electric service. [A.A.C. R14-2-201-(2)]

b. Application means a request to the utility for electric service, as distinguished from an inquiry as to the availability or charges for such service. [A.A.C. R14-2-201-(3)]

c. Billing Month means the period between any two regular readings of the utility's Meters at approximately 30 day intervals. [A.A.C. R14-2-201-(5)]

d. Billing Period means the time interval between two consecutive Meter readings that are taken for billing purposes. [A.A.C. R14-2-201-(6)]

e. Customer means the person or entity in whose name service is rendered, as evidenced by the signature on the Application or contract for that service, or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service. [A.A.C. R14-2-201-(9)]

f. Delinquent Bill means a bill in which current electric charges are considered past due. (15 *calendar* days after the statement date)

g. Demand means the rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units. [A.A.C. R14-2-201-(12)]

h. Distribution Lines means the utility lines operated at distribution voltage which are constructed along public roadways or other bona fide rights-of-way, including Easements on Customer's property. [A.A.C. R-14-2-201-(13)]

i. Easement means a property owner grants the right to use land they own ("Grantor') to another party. An easement gives Company the right to have Company lines on property not owned by the Company. This allows Company to construct, replace, repair, operate and maintain electrical equipment for the safe transmission and distribution of electricity. The Grantor may continue to use the land along the easement within certain limitations.

j. Landlord Automatic Transfer of Service Agreement is a legal contract established between the customer (landlord) and Company, which provides continuous service to the landlord between tenants without incurring a service establishment charge to the landlord.

k. Master meter means a meter used for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage. [A.A.C. R14-2-201(23)]

l. Meter means the instrument used for measuring and indicating or recording the flow of electricity that has passed through it. [A.A.C. R14-2-201(25)]

m. Meter tampering means a situation where a meter has been altered or bypassed without prior written authorization from Company. Common examples are meter bypassing, use of magnets to slow the meter recording, and broken meter seals. [A.A.C. R14-2-201(26)]

n. Minimum charge means the amount the customer must pay for the availability of electric service, including an amount of usage, as specified in the utility's tariffs. [A.A.C. R14-2-201(27)]

o. Point of delivery or delivery point means the point where facilities owned, leased, or under license by a customer connects to the utility's facilities. [A.A.C . R14-2-201(31)]

p. Service establishment charge means the charge for establishing a new account.

q. Tariffs mean the documents filed with the Arizona Corportion Commission which list the services and products offered by the utility and which set forth the terms and conditions and a schedule of the rates and charges, for those services and products. [A.A.C. R14-2-201(42)]

Statement of Charges

Description	Charge	Reference
Residential Service Establishment Charge	$25.00	2.2
Non-Residential Service Establishment Charge	$35.00	2.2
Trip Charge	$16.00	2.2.1
After hours Charge	$75.00	2.2.2
Same Day Connect Charge	$75.00	2.2.3
Non-standard Connect Charge	$75.00 per crew per hour	2.2.4
Direct Access Request	$10.00	2.3
Dishonored Payment Fee	$15.00	4.4.1
Field Call Charge	$15.00	4.5.1
Overhead Reconnection Charge	$96.50	4.5.2
Underground Reconnection Charge	$115.00	4.5.2
Lock Ring Key Charge	$70.00	6.2.2
Joint Site meeting for removal of Company Equipment	$62.00 per site per first half hour. Additional charge per hour for site meeting over one half hour	6.2.3

	will be $53.00 per hour.	
Meter Reread	$16.50	6.4.4 & 6.4.5
Meter test in shop	$30.00	6.5
Meter test at site	$50.00	6.5
Electronically Transmitted Payment Discount	-$0.48	4.3.3

1. General

1.1 Services will be supplied in accordance with these Terms and Conditions and any changes required by law, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of the Customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required.

1.2 These Terms and Conditions shall be considered a part of all rate schedules, except where specifically changed by a written agreement.

1.3 In case of a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule shall apply.

2. Establishment of Service

2.1 Application for Service - Customers requesting service may be required to appear at Company's place of business to produce proof of identity and/or sign Company's standard form of Application for service or a contract before service is supplied by Company.

2.1.1 In the absence of a signed Application or contract for service, the supplying of Standard Offer and/or Direct Access services by Company and acceptance thereof by the Customer shall be deemed to constitute a service agreement by and between Company and the Customer for delivery of, acceptance of, and payment for service, subject to Company's applicable rates and rules and regulations.

2.1.2 Where service is requested by two or more individuals, Company shall have the right to collect the full amount owed Company from any one of theCustomers.

2.2 Service Establishment and Customer Request for Special Service Charge - A Service Establishment Charge of $25.00 for residential and $35.00 non-residential plus any applicable tax adjustment will be assessed each time Company is requested to establish, reconnect or re-establish electric service to the Customer's Delivery Point, or to make a special read without a disconnect and calculate a bill for a partial month

2.2.1 The Customer will additionally be required to pay a trip charge of $16.00 when an authorized Company representative travels to the Customer's site and is unable to complete the Customer's requested services due to lack of access to the Point of Delivery.

2.2.2 The Customer will additionally be required to pay an after-hours charge of $75.00 if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established after 5:00 p.m. on a day other than the day of request.

2.2.3 The Customer will additionally be required to pay a same day connect charge of $75.00 if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established on the same business day the request is being made, and Company agrees to work the request on the same business day of the request. This will be charged regardless of the time the order may be worked by Company on that day. Company may, where no additional costs are incurred by Company, waive the same day fee.

2.2.4 The Customer will additionally be required to pay $75.00 per crew person per hour when Customer requests services that do not meet the definition of service establishment as defined in A.A.C. R14-2-203.D.3 (such as Customer requested outages for maintenance and metering equipment installations which include instrument transformers) that require the availability of Company representatives after hours, on a weekend day, or on a Company holiday. The number of representatives utilized by Company in fulfilling such requests shall be at the sole discretion of Company. Customers will be given notice of estimated charges prior to the work being performed.

Company holidays are New Year's Day, Martin Luther King Jr. Day, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, The Day After Thanksgiving, and Christmas Day.

2.2.5 Company may waive the Service Establishment Charge where:

2.2.5.1 No field trip is required because Applicant accepts responsibility for energy billed and not yet paid and the change is effective with the last Meter read and Meter read date billed.

2.2.5.2 Applicant has an active Landlord Automatic Transfer of Service Agreement on file with Company. This service agreement is for property owners that have established credit with Company and provides for continuous service to the landlord between tenants.

2.2.5.3 Where multiple connects are performed during the same site visit, in the same Applicant name, at the same address, for the same class of service, Company will assess the Service Establishment Charge once for every two Delivery Points.

2.3 Direct Access Service Request (DASR) - A Direct Access Service Request charge of $10.00 plus any applicable tax adjustment will be assessed to the Electric Service Provider (ESP) submitting the DASR each time Company processes a Request (RQ) type DASR as specified in Company's Schedule 10, Terms and Conditions for Direct Access.

2.4 Grounds for Refusal of Service - Company may refuse to connect or reconnect Standard Offer or Direct Access service if any of the following conditions exist:

2.4.1 The Applicant has an outstanding amount due with Company for the same class of service and is unwilling to make payment arrangements that are acceptable to Company.

2.4.2 A condition exists which in Company's judgment is unsafe or hazardous.

2.4.3 The Applicant has failed to meet the security deposit requirements set forth by Company as specified under Section 2.5 or 2.6 hereof.

2.4.4 The Applicant is known to be in violation of Company's Tariff.

2.4.5 The Applicant fails to furnish such funds, service, equipment, and/or rights-of-way or Easements required to serve the Applicant and which have been specified by Company as a condition for providing service.

2.4.6 The Applicant falsifies his or her identity for the purpose of obtaining service.

2.4.7 Service is already being provided at the address for which the Applicant is requesting service.

2.4.8 Residential service is requested by an Applicant and a prior Customer, who will be living at the subject address, owes a delinquent bill from the same or a prior residential service address.

2.4.9 Service is requested by an Applicant, and a prior Customer who will be an actual user of the service at the subject address owes a delinquent bill for the same class of service from the same or a prior service address.

2.4.10 The Applicant has failed to obtain all required permits and/or inspections indicating that the Applicant's facilities comply with local construction and safety codes.

2.5 Establishment of Credit or Security Deposit

2.5.1 Residential Establishment of Credit - Company shall not require a security deposit from a new Applicant for service at a primary and/or secondary residence if the Applicant is able to meet any of the following requirements:

2.5.1.1 The Applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.1.2 Company receives an acceptable credit rating, as determined by Company, for the Applicant from a credit rating agency utilized by Company.

2.5.1.3 The Applicant can produce a letter regarding credit or verification from an electric utility where service of a comparable nature was last received within six (6) months of the current date which states that the Applicant had a timely payment history for the prior twelve (12) consecutive months at the time of service discontinuation.

2.5.1.4 In lieu of a security deposit, Company receives deposit guarantee notification from a social or governmental agency acceptable to Company or a surety bond as security for Company in a sum equal to the required deposit.

2.5.1.5 Where three or more additional residential services are requested, Company may require Customer to establish or reestablish a security deposit.

2.5.2 Residential Establishment of Credit or Security Deposit - When credit cannot be established as provided for in Section 2.5.1 hereof or when it is determined that the Applicant left an unpaid final bill owing to another utility company, the Applicant will be required to:

2.5.2.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.2.2 Provide a surety bond acceptable to Company in an amount equal to the required security deposit.

2.5.3 Non-residential Establishment of Security Deposit – All non-residential Applicants will be required to place a cash deposit to secure payment of bills for service as prescribed herein, unless:

2.5.3.1 The Applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.3.2 The Applicant provides a non-cash security deposit in the form of a Surety Bond, Irrevocable Letter of Credit, or Assignment of Monies in an amount equal to the required security deposit.

2.6 Establishment or Reestablishment of Security Deposit

2.6.1 Residential - Company may require a residential Customer to establish or re-establish a security deposit if the Customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or has been disconnected for non-payment during the last twelve (12) months.

2.6.2 Non-residential - Company may require a non-residential Customer to establish or re-establish a security deposit if the Customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or if the Customer has been disconnected for non-payment during the last twelve (12) months, or when the Customer's financial condition may jeopardize the payment of their bill, as determined by Company based on the results of using a credit scoring worksheet. Company will inform all Customers of the Arizona Corporation Commission's complaint process should the Customer dispute the deposit based on the financial data.

2.7 Security Deposits – Once it is determined that a security deposit is required, the following will apply:

2.7.1 Security deposits may be required for each service location.

2.7.2 Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by Company in accordance with this section:

2.7.2.1 If the Customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount which reflects that portion of the Customer's service being provided by a Load Serving ESP. However if the Load Serving ESP is providing ESP Consolidated Billing pursuant to Company's Schedule 10 Section 7, the entire deposit will be credited to the Customer's account; or,

2.7.2.2 If the Customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount pursuant to Section 2.5, which reflects that Company is providing bundled electric service.

2.7.2.3 If the Customer's average consumption increases: by more than ten (10) percent for residential accounts or five (5) percent for nonresidential accounts within a twelve (12) consecutive month period and credit has not been established, an additional security deposit may, at Company's option, be required.

2.7.3 Customer security deposits shall not preclude Company from terminating an agreement for service or suspending service for any failure in the performance of Customer obligation under the agreement for service.

2.7.4 Cash deposits held by Company six (6) months/183 days or longer shall earn interest from the date the deposit was collected at the established one year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website. Deposits on inactive accounts are applied to the final bill when all service options become inactive, and the balance, if any, is refunded to the Customer of record within thirty (30) days. For refunds resulting from the Customer changing from Standard Offer to Direct Access, the difference in the deposit amounts will be applied to the Customer's account.

2.7.5 If the Customer terminates all service with Company, the security deposit may be credited to the Customer's final bill.

2.7.6 Residential security deposits shall not exceed the higher amount of either one (1) time the Customer's maximum monthly bill or two (2) times the Customer's average monthly bill as estimated by Company for the services being provided by Company.

2.7.6.1 Deposits or other instruments of credit will automatically expire or be credited or returned to the Customers account after twelve (12) consecutive months of service, provided the Customer has not been delinquent more than twice, unless Customer has filed bankruptcy in the last twelve (12) months.

2.7.7 Non-residential security deposits shall not exceed two and one-half (2-1/2) times the Customer's maximum monthly billing as estimated by Company for the service being provided by Company.

2.7.7.1 Deposits and non-cash deposits on file with Company will be reviewed after twenty-four (24) months of service and will be returned provided the Customer has not been delinquent more than twice in the payment of bills or disconnected for non-payment during the previous twelve (12) consecutive months unless the Customer's financial condition warrants extension of the security deposit.

2.8 Line Extensions Service requests requiring Company to extend or upgrade its facilities in order to establish service will be made in accordance with Company's Service Schedule #3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

2.9 Customer-Specific Information - Customer-specific information shall not be released without specific prior written Customer authorization unless the information is requested by law enforcement or other public agency, or is requested by the Arizona Corporation Commission or its staff, or is reasonably required for legitimate account collection activities, or is necessary to provide efficient, effective, safe, or reliable service to the Customer. Customer-specific information may be provided to suppliers of goods or services under contract with Company if:

2.9.1 Such goods or services will assist Company in providing efficient, effective, safe, or reliable service; and

2.9.2 Such contract includes a requirement that the information be kept confidential and is only used to fulfill the supplier's obligations to Company.

3. Rates

3.1 Rate Information - Company shall provide, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to that Customer for the requested type of service. In addition, Company shall notify its Customers of any changes in Company Tariff affecting those Customers.

3.2 Rate Selection – The Customer's service characteristics and service requirements determine the selection of applicable rate schedule. If the Customer is receiving bundled service, Company will use reasonable care in initially establishing service to the Customer under the most advantageous rate schedule applicable to the Customer. However, because of varying Customer usage patterns and other reasons beyond its reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. Company will not make any refunds in any instances where it is determined that the Customer would have paid less for service had the Customer been billed on an alternate applicable rate or provision of that rate.

3.3 Optional Rates – Certain optional rate schedules applicable to certain classes of service allow the Customer the option to select the rate schedule to be effective initially or after service has been established. Billing under the alternate rate will become effective from the next regularly scheduled Meter reading, after the appropriate metering equipment is installed. No further rate schedule changes, however, may be made within the succeeding twelve (12) month period. Where

the rate schedule or contract pursuant to which the Customer is provided service specifies a term, the Customer may not exercise its option to select an alternate rate schedule until expiration of that term.

3.4 Direct Access service will be effective upon the next Meter read date if DASR is processed fifteen (15) calendar days prior to that read date and the appropriate metering equipment is in place. If a DASR is made less than fifteen (15) days prior to the next regular read date the effective date will be at the next Meter read date thereafter. The above timeframes are applicable for Customers changing their selection of Electric Service Providers or for Customers returning to Standard Offer service.

3.5 Any Customer that selects Direct Access service may return to Standard Offer service in accordance with the rules, regulations, and orders of the Arizona Corporation Commission. However, such Customer will not be eligible for Direct Access service for the succeeding twelve (12) month period. If a Customer returning to Standard Offer, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will only apply if the Customer fails to select another ESP within sixty (60) days of returning to Standard Offer service.

4. Billing and Collection

4.1 Customer Service Installation and Billing - Service Billing Periods normally consist of approximately thirty (30) days unless designated otherwise under rate schedules, through contractual agreement, or at Company option.

4.1.1 Company normally Meters and bills each site separately; however, at Customer's request, adjacent and contiguous sites (not separated by private or public property or right of way), operated as one integral unit under the same name and as a part of the same business, may at Company's option be considered a single site as specified in Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

4.1.2 The Customer's service installation will normally be arranged to accept only one type of service at one Point of Delivery to enable service measurement through one Meter. If the Customer requires more than one type of service, or total service cannot be measured through one Meter according to Company's regular practice, separate Meters will be used and separate billing rendered for the service measured by each Meter.

4.2 Collection Policy - The following collection policy shall apply to all Customer accounts:

4.2.1 All bills rendered by Company are due and payable no later than fifteen (15) calendar days from the billing date. Any payment not received within this time frame will be considered delinquent. All delinquent bills for which payment has not been received shall be subject to the provisions of Company's termination procedure. Company reserves the right to suspend or terminate the Customer's service for non-payment of any Arizona Corporation Commission approved charges. All delinquent charges will be subject to a late charge at the rate of eighteen percent (18%) per annum.

4.2.2 If the Customer, as defined in A.A.C. R 14-2-201.9, has two or more services with Company and one or more of such services is terminated for any reason leaving an outstanding bill and the Customer is unwilling to make payment arrangements that are acceptable to Company, Company shall be entitled to transfer the balance due on the terminated service to any other active account of the Customer for the same class of service. The failure of the Customer to pay the active account shall result in the suspension or termination of service thereunder.

4.2.3 Unpaid charges incurred prior to the Customer selecting Direct Access will not delay the Customer's request for Direct Access. These charges remain the responsibility of the Customer to pay. Normal collection activity, including discontinuing service, may be followed for failure to pay.

4.2.4 All unpaid delinquent final bills may be referred to a collection agency for collection.

4.2.4.1 If collection agency referral is warranted for collection of unpaid final bills, Customer will be responsible for associated collection agency fees incurred.

4.3 Responsibility for Payment of Bills

4.3.1 The Customer is responsible for the payment of bills until service is ordered discontinued and Company has had reasonable time to secure a final Meter reading for those services involving energy usage, or if non-metered services are involved until Company has had reasonable time to process the disconnect request.

4.3.2 When an error is found to exist in the billing rendered to the Customer, Company may correct such an error to recover or refund the difference between the original billing and the correct billing. Such adjusted billings will not be rendered for periods in excess of the applicable statute of limitations from the date the error is discovered. Schedule 8 (Bill Estimation) shall be applied when Company cannot obtain a complete and valid Meter read. Situations that result in an estimated Meter read include inclement weather, lack of access to a Customer's Meter, energy diversion, labor unavailability and equipment malfunction.

4.3.2.1 Refunds or credits to Customers resulting from overbillings will be made promptly upon discovery by Company.

4.3.2.2 Corrected charges for underbillings shall be billed to the Customer who shall be given an equal length of time such as number of months underbilled to pay the backbill without late payment penalties, unless there is evidence of Meter Tampering or energy diversion.

4.3.2.3 Except as specified below, corrected charges for underbillings shall be limited to three (3) month for residential accounts and six (6) months for non-residential accounts.

4.3.2.3.1 Where the account is billed on a special contract or non-metered rate, corrected charges for underbillings shall be billed in accordance with

the contract or rate schedule requirements and is not limited to three or six months as applicable.

4.3.2.3.2 Where service has been established but no bills have been rendered, corrected charges for underbillings shall go back to the date service was established.

4.3.2.3.3 Where there is evidence of Meter Tampering or energy diversions, corrected charges for underbillings shall go back to the date Meter Tampering or energy diversions began, as determined by Company.

4.3.2.3.4 Where lack of access to the Meter (caused by the Customer) has resulted in estimated bills, corrected charges for underbillings shall go back to the Billing Month of the last Company obtained Meter read date.

4.3.2.3.5 Where actual Customer usage can be determined without estimating reads, corrected charges for underbillings are not limited to three or six months, as applicable. In no event shall such rebilling exceed the applicable statute of limitations.

4.3.2.4 Company may forgo billing and collection of corrected charges for an underbilling if Company believes the cost of billing and collecting the underbilling would not justify pursuing the underbill.

4.3.3 Where Company is responsible for rendering the Customer's bill, Company will provide a monthly incentive of $0.48 per Customer to Customers who elect to pay their bills using the Company's electronically transmitted payment options AutoPay, SurePay or similar programs.

4.4 Dishonored Payments - If Company is notified by the Customer's financial institution that they will not honor a payment tendered by the Customer for payment of any bill, Company may require the Customer to make payment in cash, by money order, certified or cashier's check, or other means which guarantee the Customer's payment to Company.

4.4.1 The Customer will be charged a fee of $15.00 for each instance where the Customer tenders payment of a bill with a payment that is not honored by the Customer's financial institution.

4.4.2 The tender of a dishonored payment shall in no way (i) relieve the Customer of the obligation to render payment to Company under the original terms of the bill, or (ii) defer Company's right to terminate service for nonpayment of bills.

4.4.3 Where the Customer has tendered two (2) or more dishonored payments in the past twelve (12) consecutive months, Company may require the Customer to make payment in cash, money order or cashier's check for the next twelve (12) consecutive months.

4.5 Termination Process Charges

4.5.1 Company will require payment of a Field Call Charge of $15.00 when an authorized Company representative travels to the Customer's site to accept payment on a delinquent account, notify of service termination, make payment arrangements or terminate the service. This charge will only be applied for field calls resulting from the termination process.

4.5.2 If a termination is required at the pole, a reconnection charge of $96.50 will be required; if the termination is in underground equipment, the reconnection charge will be $115.00.

4.5.3 To avoid termination of service, the Customer will make payment in full, including any necessary deposit in accordance with Section 2.5 hereof or make payment arrangements satisfactory to Company.

5. Service Responsibilities of Company and Customer

5.1 Service Voltage –Company will deliver electric service to the designated Point of Delivery, as specified in Section 6.3 of this Schedule, at the standard voltages specified in the Electric Service Requirements Manual published by Company and as specified in A.A.C. R14-2-208.F. Company may deliver service for special Applications at higher voltages, with prior approval from Company's Engineering Department and in accordance with Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

5.2 Responsibility: Use of Service or Apparatus

5.2.1 The Customer shall save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or the use thereof on the Customer's side of the Point of Delivery. Company shall have the right to suspend or terminate service in the event Company should learn of service use by the Customer under hazardous conditions.

5.2.2 The Customer shall exercise all reasonable care to prevent loss or damage to Company property installed on the Customer's site for the purpose of supplying service to the Customer.

5.2.3 The Customer shall be responsible for payment for loss or damage to Company property on the Customer's site arising from neglect, carelessness or misuse and shall reimburse Company for the cost of necessary repairs or replacements.

5.2.4 The Customer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the Meter.

5.2.5 The Customer shall be responsible for notifying Company of any failure in Company's equipment.

5.3 Service Interruptions: Limitations on Liability of Company

5.3.1 Company shall not be liable to the Customer for any damages occasioned by Load Serving ESP's equipment or failure to perform, fluctuations, interruptions or curtailment of electric service, except where due to Company's willful misconduct or gross negligence. Company may, without incurring any liability therefore, suspend the Customer's electric service for periods reasonably required to permit Company to accomplish repairs to or changes in any of Company's facilities. The Customer needs to protect their own sensitive equipment from harm caused by variations or interruptions in power supply.

5.3.2 In the event of a national emergency or local disaster resulting in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

5.4 Company Access to Customer Sites

5.4.1 Company's authorized agents shall have satisfactory unassisted twenty-four (24) hour a day, seven (7) days a week access to Company's equipment located on Customer's sites for the purpose of repair, maintenance, and service restoration work that Company may need to perform.

5.4.2 Company's authorized agents shall have satisfactory unassisted access to the Customer's sites at all reasonable hours to install, inspect, read, repair or remove its Meters or to install, operate or maintain other Company property, to verify that Customer is in compliance with its obligations, or to inspect and determine the connected electrical load. If, after six (6) months (not necessarily consecutive) of good faith efforts by Company to work with the Customer, Company in its opinion does not have satisfactory unassisted access to the Meter, then Company shall have sufficient cause for termination of service or denial of any rate options where, in Company's opinion, access is required. The remedy for unassisted access will be at Company discretion and may include the installation by Company of a specialized Meter. If such specialized Meter is installed, the Customer will be billed the difference between the otherwise applicable Meter for their rate and the specialized Meter plus the cost incurred to install the specialized Meter as a one-time charge and any reoccurring incremental costs. If service is terminated as a result of failure to provide unassisted access, Company verification of unassisted access may be required before service is restored. Written termination notice is required prior to disconnecting service under this section.

5.5 Easements

5.5.1 All suitable Easements or rights-of-way required by Company for any portion of an extension to serve a Customer, which is either on sites owned, leased or otherwise controlled by the Customer or developer, or other property required for the extension, shall be furnished in Company's name by the Customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All

Easements or rights-of-way granted to, or obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.5.2 When Company discovers that the Customer or the Customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow, adjacent to or within an Easement or right-of-way or Company-owned equipment, and such work, construction, vegetation or facility poses a hazard or is in violation of federal, state, or local laws, ordinances, statutes, rules or regulations, or significantly interferes with Company's safe use, operation or maintenance of, or access to, equipment or facilities, Company shall notify the Customer or the Customer's agent and shall take whatever actions are necessary to eliminate the hazard, obstruction, interference or violation at the Customer's expense. Company will notify the Customer in writing of the violations.

5.6 Load Characteristics – The Customer shall exercise reasonable care to ensure that the electrical characteristics of its load, such as deviation from sine wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in Demand, shall not impair service to other Customers or interfere with operation of telephone, television, or other communication facilities. Customer shall meet power factor requirements as specified on applicable rate schedules.

6. Metering and Metering Equipment

6.1 Customer Equipment - The Customer shall install and maintain all wiring and equipment beyond the Point of Delivery except for Company's Meters and special equipment. The Customer's entire installation must conform to all applicable construction standards and safety codes and the Customer must furnish an inspection or permit if required by law or by Company. In circumstances where a clearance is not required by law, Company may require Customer to execute a Letter In-Lieu of Electrical Clearance.

6.1.1 The Customer shall provide, in accordance with Company's current service standards and/or Electric Service Requirements Manual, at no expense to Company, and close to the Point of Delivery, a sufficient and suitable space acceptable to Company's agent for the installation, accessibility and maintenance of Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line at http://esp.apsc.com/resource/metering.asp.

6.1.2 Where a Customer requests, and Company approves, a special Meter reading device or communications services or devices to accommodate the Customer's needs, the cost for such additional equipment and usage fees shall be the responsibility of the Customer.

6.2 Company Equipment

6.2.1 A Meter Service Provider (MSP) or its authorized agents may remove Company's metering equipment pursuant to Company's Schedule 10. Meters not returned to Company or returned damaged will result in charge to the MSP of the replacement costs, plus an administration fee of fifteen percent (15%), less five (5) years depreciation.

6.2.2 Company will lease lock ring keys to MSP's and/or their agents authorized to remove Company Meters pursuant to the terms and conditions of Company's Schedule 10 at a

refundable charge of $70.00 per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace ten percent (10%) of the issued keys within any twelve (12) month period due to loss by the MSP's agent, Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint meeting. All lock ring keys must be returned to Company within five (5) working days if the MSP and/or its authorized agents are:

1) No longer permitted to remove Company Meters pursuant to conditions of Company's Schedule 10;
2) No longer authorized by the Arizona Corporation Commission to provide services; or
3) The ESP Agreement has been terminated.

6.2.3 If the MSP, the Customer, and/or its agent request a joint site meeting for removal of Company metering and associated equipment and/or lock ring, a base charge will be assessed of $62.00 per site. Company may assess an additional charge of $53.00 per hour for joint site meetings that exceed thirty (30) minutes. If Company must temporarily replace the MSP's Meter and/or associated metering equipment during emergency situations or to restore power to a Customer, the above charges may apply.

6.3 Service Connections - Company is not required to install and maintain any lines and equipment on the Customer's side of the Point of Delivery except its Meter.

6.3.1 For overhead service, the Point of Delivery shall be where Company's service conductors terminate at the Customer's weatherhead or bus rider.

6.3.2 For underground service, the Point of Delivery shall be where Company's service conductors terminate in the Customer's or development's service equipment. The Customer shall furnish, install and maintain any risers, raceways and/or termination cabinet necessary for the installation of Company's underground service conductors.

6.3.3 For special Applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, Company and Customer shall mutually agree upon the designated Point of Delivery.

6.3.4 For the mutual protection of the Customer and Company, only authorized employees or agents of Company or the Load Serving ESP are permitted to make and energize the connection between Company's service wires and the Customer's service entrance conductors. Such employees carry Company issued identification which they will show on request.

6.4 Measuring Customer Service - All the energy sold to the Customer will be measured by commercially acceptable measuring devices by Company (or the Meter Reading Service Provider (MRSP) pursuant to the terms and conditions of Company's Schedule 10). Where energy and, if applicable, Demand is estimated by Company, estimation will be in accordance with Company's bill estimation procedures approved by the Arizona Corporation Commission. Where it is impractical to Meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by Company.

6.4.1 For Standard Offer Customers, or where Company is the MRSP, the readings of the Meter will be conclusive as to the amount of electric power supplied to the Customer unless there is evidence of Meter Tampering or energy diversion, or unless a test reveals the Meter is in error by more than plus or minus three percent (3%).

6.4.2 If there is evidence of Meter Tampering or energy diversion, the Customer, person or entity demonstrated to have tampered with the Meter and/or benefited from the tampering or diversion will be billed for the estimated energy and, if applicable, Demand, for the period in which the energy diversion took place. Additionally, where there is evidence of Meter Tampering, energy diversion, or by-passing the Meter, the Customer, person or entity demonstrated to have tampered with the Meter and/or diverted energy will also be charged the cost of the investigation as determined by Company.

6.4.3 If after testing, a Meter is found to be more than three percent (3%) in error, either fast or slow, proper correction shall be made of previous readings and adjusted bills shall be rendered or adjusted billing information will be provided to the MRSP.

6.4.3.1 Customer will be billed, in accordance with Section 4.3.2, for the estimated energy and Demand that would have registered had the Meter been operating properly.

6.4.4 Where Company is the MRSP, Company will, at the request of the Customer or the ESP, reread the customer's Meter within ten (10) working days after such request by the Customer. The cost of such rereads is $16.50 and may be charged to the Customer or the ESP, provided that the original reading was not in error.

6.4.5 Where the ESP is the MSP or MRSP, and the ESP and/or its' agent fails to provide the Meter data to Company pursuant to Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, Company may, at its option, obtain the data, or may estimate the billing determinants. The charge for such reread is $16.50 and may be charged to the ESP.

6.5 Meter Testing - Company tests its Meters regularly in accordance with a Meter testing and maintenance program as approved by the Arizona Corporation Commission. Company will, however, individually test a Company owned/maintained Meter upon Customer or ESP request. If the Meter is found to be within the plus or minus three percent (3%) limit, Company may charge the Customer or the ESP $30.00 for Meter test if the Meter is removed from the site and tested in the meter shop, and $50.00 if the Meter remains on site and is tested in the field.

6.6 Master Metering

6.6.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

6.6.2 Residential Apartment Complexes - Company shall refuse service to all new construction of apartment complexes and condominiums which are Master Metered. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

6.6.3 Multi-Unit Residential High Rise Developments (developments consisting of apartments, condominiums or townhouse developments built with four or more floors, usually using elevators for accessing floors) – Company will allow Master Metering for residential units where the residential units are privately owned, provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

6.6.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

6.6.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

7. Termination of Service

7.1 With Notice - Company may without liability for injury or damage, and without making a personal visit to the site, disconnect service to any Customer for any of the reasons stated below, provided Company has met the notice requirements established by the Arizona Corporation Commission:

7.1.1 A Customer violation of any of the applicable rules of the Arizona Corporation Commission or Company Tariff.

7.1.2 Failure of the Customer to pay a Delinquent Bill for services provided by Company.

7.1.2.1 Additional notice will not be provided when Customer makes payments to avoid/stop non-payment disconnection with a dishonored payment. Prior to reconnection of service, repayment of those funds and all other delinquent amounts will be required in cash, money order, or certified funds.

7.1.2.2 Additonal notice will not be provided when Customer pays to reconnect service with a dishonored payment. Prior to reconnection of service, payment of those funds and all other delinquent amounts will be required in cash, money order or certified funds.

7.1.3 The Customer's breach of a written contract for service.

7.1.4 Failure of the Customer to comply with Company's deposit requirements.

7.1.5 Failure of the Customer to provide Company with satisfactory and unassisted access to Company's equipment.

7.1.6 When necessary to comply with an order of any governmental agency having jurisdiction.

7.1.7 Failure of a prior Customer to pay a Delinquent Bill for utility services where the prior Customer continues to reside on the premises.

7.1.8 Failure to provide or retain rights-of-way or Easements necessary to serve the Customer.

7.1.9 Company learns of the existence of any condition in Section 2.4, Grounds For Refusal of Service.

7.2 Without Notice - Company may without liability for injury or damage disconnect service to any Customer without advance notice under any of the following conditions:

7.2.1 Company observes, or has evidence of, a hazard to the health or safety of persons or property.

7.2.2 Company has evidence of Meter Tampering or fraud.

7.2.3 Company has evidence of unauthorized resale or use of electric service.

7.2.4 Failure of the Customer to comply with the curtailment procedures imposed by Company during a supply shortage.

7.3 Restoration of Service - Company shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of Company.

8. Removal of Facilities - Upon termination of service, Company may without liability for injury or damage, dismantle and remove its facilities installed for the purpose of supplying service to the Customer, and Company shall be under no further obligation to serve the Customer.

9. Successors and Assigns - Agreements for Service shall be binding upon and for the benefit of the successors and assigns of the Customer and Company, but no assignments by the Customer shall be effective until the Customer's assignee agrees in writing to be bound and until such assignment is accepted in writing by Company.

10. Warranty - THERE ARE NO UNDERSTANDINGS, AGREEMENTS, REPRESENTATIONS, OR WARRANTIES, EXPRESS OR IMPLIED (INCLUDING WARRANTIES REGARDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), NOT SPECIFIED HEREIN OR IN THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION CONCERNING THE SALE AND DELIVERY OF SERVICES BY COMPANY TO THE CUSTOMER. THESE TERMS AND CONDITIONS AND THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION STATE THE ENTIRE OBLIGATION OF COMPANY IN CONNECTION WITH SUCH SALES AND DELIVERIES.

Schedule 2

The following TERMS AND CONDITIONS and any changes authorized by law, regulation, rule or order of applicable governmental authority will apply to the purchase of electric energy under the established rate or rates authorized by law and currently applicable at time of purchase; and these TERMS AND CONDITIONS shall be considered a part of all of Company's rate schedules for purchases except where specifically changed by written agreement.

1. DEFINITIONS

1.1 Point Of Interconnection - The point where Company's service conductors are connected to Customer's service conductors.

1.2 Qualifying Facility (QF) - Any cogeneration or small power production facility that meets the criteria for size, fuel use, efficiency, and ownership as promulgated in 18 CFR, Chapter I, Part 292, Subpart B of the Federal Energy Regulatory Commission's Regulations.

1.3 Purchase Agreement - The agreement entered into between Customer and Company detailing the provisions for the purchase of electric energy by Company from Customer's QF, and the sale, if any, of power by Company to Customer.

1.4 Cogeneration Facility - Any facility that sequentially produces electricity, steam or forms of useful energy (e.g., heat) from the same fuel source and which are used for industrial, commercial, heating, or cooling purposes.

1.5 Small Power Production Facility - A facility that uses primarily biomass, waste, or renewable resources, including wind, solar, and water to produce electric power.

2. CUSTOMER'S OBLIGATIONS

2.1 Customer agrees not to commence interconnected operation of its QF with Company's system, until the installation has been inspected by an authorized Company representative and final written approval is received from Company to commence interconnected operation. Customer shall give reasonable notice to Company when initial startup is to begin. Company shall have the right to have a representative present during initial energizing and testing of Customer's system.

2.2 Customer shall own and be fully responsible for the costs of designing, installing, operating and maintaining:

2.2.1 The QF in accordance with the requirements of all applicable electric codes, laws and governmental agencies having jurisdiction.

2.2.2 Control and protective devices to protect its facilities from abnormal operating conditions such as, but not limited to, electrical overloading, abnormal voltages, and fault currents. Such protective devices shall promptly disconnect the QF from Company's system in the event of a power outage on Company's system.

2.2.3 A gang operated load break disconnect switch, capable of being locked in a visibly open position that will completely isolate the QF from Company's system. Such disconnect switch shall be installed in a place easily accessible to Company's personnel. Company shall have the right to lock open the disconnect switch without notice to Customer when interconnected operation of the QF with Company's system could adversely affect Company's system or endanger life or property.

2.2.4 Interconnection facilities on Customer's premises as may be required to deliver power from Customer's QF to Company's system at the agreed Point Of Interconnection.

2.3 Electric sales to Company must be single or three phase, 60 Hertz, at one standard voltage (12,500; 2400/4160; 480; 277/480; 120/240 or 120/208 volts as may be selected by Customer subject to availability at the premises). Customer's facilities shall also maintain a minimum ninety percent (90%) leading to ninety percent (90%) lagging power factor as measured at the Point Of Interconnection.

2.4 The electrical output of Customer's QF shall not contain harmonic content which may cause disturbances on or damage to Company's electrical system, or other party's systems, such as but not limited to communication systems.

2.5 Customer shall operate and maintain the QF in accordance with those practices and methods, as they are changed from time-to-time, that are commonly used in prudent engineering and electric utility operations and shall operate the QF lawfully and in a safe, dependable and efficient manner.

2.6 Customer shall submit to Company written equipment specifications and detailed plans to Company for the installation and operations of its QF, interconnection facilities, control and protective devices and facilities to accommodate Company's meter(s) for review and advance written approval prior to their actual installation. After Company's approval Customer shall not change or modify equipment specifications, plans, control and protective devices, metering and in general the QF's system configuration. If Customer desires to make such changes or modifications, Customer shall resubmit to Company plans describing said changes or modifications for approval by Company. No such change or modification may be made without the prior written approval of Company.

2.7 In the event it is necessary for Company to install interconnection facilities on its system (including, but not limited to control or protective devices, or any other facilities) in order to receive or continue to receive or to deliver electric power under the terms of the Purchase Agreement, Company shall inform Customer of the cost thereof in advance of incurring the costs of such facilities and Customer shall reimburse Company for the costs incurred by Company in connection with such facilities to the extent that said costs exceed those normally incurred by Company with respect to those customers which it serves who do not have self generation facilities.

2.8 If Customer utilizes the Company's system to facilitate start-up of its QF, the voltage flicker level shall not exceed Company standards.

3. METERING PROVISIONS

3.1 Customer shall provide and install at no expense to Company, and in accordance with Company's service standards, meter sockets and metering cabinets in a suitable location to be determined by Company's representatives.

3.2 Company shall furnish, own, install and maintain all meters that register the sales of power to, and the purchases of energy from Customer. The responsibility for the costs of providing and maintaining the required meters shall be as outlined in the applicable Rate for Purchase, or as specified in the Purchase Agreement.

3.3 The readings of all said meters will be conclusive as to the amount of electric power and energy supplied to the QF and/or purchased by Company unless, upon test, the meters are found to be in error by more than three percent (3%). The expense of any meter test requested by Customer will be borne by Customer unless such test shows the meter(s) to be in error by more than three percent (3%).

4. MUTUAL UNDERSTANDINGS

4.1 Company shall be allowed to install on Customer's premises any instrumentation equipment for research purposes. Such equipment shall be owned, furnished, installed and maintained by Company.

4.2 Company's approvals given pursuant to the Purchase Agreement shall not be construed as any warranty or representation to Customer or any third party regarding the safety, durability, reliability, performance or fitness of Customer's generation and service facilities, its control or protective devices or the design, construction, installation or operation thereof.

4.3 Company (including its employees, agents, and representatives) shall have the right to enter Customer's premises at all reasonable times to (a) inspect Customer's QF, protective devices and to read or test instrumentation equipment that Company may install, provided that as reasonably possible, notice is given to Customer prior to entering its premises; (b) maintain Company equipment relative to the purchase of electric energy from Customer; (c) read or test the meters; and (d) disconnect the QF without notice if, in Company's opinion, a hazardous condition exists and such immediate action is necessary to protect persons, or Company's facilities or other customers' or third parties' property and facilities from damage or interference caused by Customer's QF, or improperly operating protective devices.

4.4 All suitable easements or rights-of-way (required by Company in order to accommodate inter-connection of Company's system with the QF), which are either on premises owned, leased or otherwise controlled by Customer, or upon other property, shall be furnished in Company's name by Customer without cost to or condemnation by Company and in reasonable time to meet the requirements of the Purchase Agreement. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

4.5 Company is not obligated to pay for electric energy or capacity from Customer during any periods when such purchases would result in costs greater than those which Company would otherwise incur had Company generated said energy itself or purchased the energy from another source. Company will give reasonable notice to Customer when such periods exist, so that Customer can discontinue deliveries of energy to Company or elect to continue to sell to Company at a rate, lower than the standard purchase rate, estimated to be the avoided system cost for the period during which such situations exist.

4.6 Company will not install and maintain any lines or equipment on Customer's side of the Point Of Interconnection except its meter (and possibly some research equipment). For the mutual protection of Customer and Company, only authorized employees of Company are permitted to make and energize the interconnection between Company's system and that of Customer's QF. Such employees carry credentials which they will show to Customer upon request.

4.7 The particular rate for purchases applicable to a QF may be dependent on the system configuration of its facilities. Because of the varied and diverse requirements and operating characteristics associated with such facilities, it will be the QF's responsibility to evaluate and determine which system configuration and attendant purchase rate is most appropriate. Company will cooperate with Customer by providing suitable information to enable the Customer to assess the options available; provided, however, that no such information or assistance shall be deemed a representation or warranty by Company with respect to the contents of such information or any particular option available to Customer.

4.8 Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules or at Company's option.

4.9 The interconnection of Company's system with that of Customer will normally be arranged to accept only one type of standard service at one Point Of Interconnection. However, if Customer's QF requires a special type of service (e.g., supplemental, back-up, maintenance or interruptible power in addition to its normal service), or its sales to Company are at a different voltage level than that of its purchases from Company, such service(s) will be provided pursuant to the specific terms outlining such requirements in the Purchase Agreement, applicable rate schedules, and/or other supplemental or special terms and conditions governing such service.

4.10 Each premises owned or controlled by Customer which is served by Company under the Purchase Agreement shall be metered and billed separately. As used herein, the term "premises" shall be deemed to mean a single tract of land owned or controlled by Customer, or separate adjacent or contiguous tracts of land owned or controlled by Customer, operated by it as one tract under the same name or as part of the same business, and not separated by any private or public lands or rights-of-way owned or controlled by third parties.

4.11 All bills rendered for Company services provided to Customer under the provisions of the Purchase Agreement are due and payable upon presentation and are past due fifteen calendar days after mailing of bill. Company reserves the right to suspend or terminate Customer's service for non-payment of service bills past due, for non-payment of interconnection charges, and for non-payment of meter test charges. Past-due service bill amounts, past-due interconnection charges and past-due meter test charges, are subject to an additional charge at the rate of 1-1/2% per month during the period of delinquency.

5. SERVICE RENDERED UNDER SPECIAL AGREEMENT

Purchases will be made from Customer's QF in accordance with the Purchase Agreement, these terms and conditions and any changes required by law, regulation, rule, or order of applicable governmental authority, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of QF's, whose requirements are of unusual size or characteristics, additional or special rate and contract arrangements may be required.

6. REGULATORY AUTHORITY

The rates, terms and other contract provisions governing electric power sold to Customer and the rates or other contract provisions for purchases by Company from Customer are subject to the jurisdiction of the Corporation Commission (ACC) and nothing contained herein shall be construed as affecting or limiting in any way the right of Company (a) to make unilateral filings of changed rates, terms and other contract provisions, which shall be effective when filed, or within a specified number of days thereafter as specified therein, such rates or other contract provisions specified in such filing to be subject to modification if required by a final decision of the ACC, or (b) to unilaterally make application to the ACC for changes in such rates or other contract provisions, following a hearing and decision as permitted by law and the ACC's rules and regulations.

7. INDEMNITY AND INSURANCE

Each Party hereby agrees to indemnify the other Party, its officers, agents, and employees against all loss, damages, expenses and liability to third persons for injury to or death of person or injury to or loss of property, proximately caused by the indemnifying Party's construction, ownership, operation, or maintenance of, or by failure of, any of such Party's works or facilities used in connection with the Purchase Agreement. The indemnifying Party shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party shall also pay all costs and expenses that may be incurred by the other Party in enforcing this indemnity.

8. UNCONTROLLABLE FORCES

No Party shall be considered to be in default in the performance of any of its obligations under the Purchase Agreement (other than obligations of said Party to pay sums to be paid by it hereunder, and other costs and expenses) when a failure of performance shall be due to an uncontrollable force. The term "uncontrollable force" shall be any cause beyond the control of the Party affected, including but not restricted to failure of or threat of failure of facilities, flood, earthquake, tornado, storm, fire, lightning, epidemic, war, riot, civil disturbance or disobedience, strikes, labor or material shortage, sabotage, restraint by court order or public authority, and action or non-action by or in- ability to obtain the necessary authorizations or approvals from any governmental agency or authority, which by exercise of due diligence such Party could not reasonably have been expected to avoid and which by exercise of due diligence it shall be unable to overcome. Nothing contained herein shall be construed so as to require a Party to settle any strike or labor dispute in which it may be involved. Either Party rendered unable to fulfill any of its obligations under this Agreement by reason of an uncontrollable force shall give prompt written notice of such fact to the other Party and shall exercise due diligence to remove such inability with all reasonable dispatch.

9. NOTICES

Any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party to the other may be so given by certified or registered mail, addressed to the Party or personally delivered to the Party at the place designated in the applicable section of the Purchase Agreement. Changes in such designation may be made by notice similarly given.

10. CONFLICTS

10.1 In case of an inconsistency or conflict between any provision of the Purchase Agreement, a rate schedule and/or these terms and conditions, the inconsistency shall be resolved by giving priority to the Purchase Agreement, the rate and then the terms and conditions in said respective order.

11. SUCCESSORS AND ASSIGNS

Purchase Agreement shall be binding upon and for the benefit of the successors and assigns of Customer and Company, but no assignment by Customer shall be binding until accepted in writing by Company (which acceptance shall not be unreasonably withheld) and until the assignee in writing assumes the obligations of Customer under the Agreement.

Schedule 3

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or the relocation and/or upgrade of existing facilities. Costs for construction depend on the applicant's location, scope of project, load size, and load characteristics. Costs include, but are not limited to, project management, coordination, engineering, design, surveys, permits, construction inspection, and support services. This schedule establishes the terms and conditions under which Company will extend, relocate, and/or upgrade its facilities in order to provide service.

All facility installations and/or upgrades shall be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company.

The following provisions govern the installation of overhead and underground electric distribution facilities to applicants whose requirements are deemed by Company to be usual and reasonable in nature.

1. DEFINITIONS

1.1. **APS Approved Electrical Distribution Contractor** means an electrical contractor who is licensed in the State of Arizona and properly qualified to install electric distribution facilities in accordance with Company standards and good utility construction practices as determined by Company.

1.2. **Conduit Only Design** means the conduit layout design for the installation of underground Extension Facilities that will be required when the Extension Facilities are to be installed at a later date.

1.3. **Corporate Business and Industrial Development** means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial and/or industrial use.

1.4. **Doubtful Permanency means** a customer who in the opinion of the Company is neither Permanent nor Temporary. Service which, in the opinion of the Company, is for operations of a speculative character is considered Doubtfully Permanent.

1.5. **Economic Feasibility** means a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the applicant.

1.6. **Execution Date** means the date Company signs the agreement after the applicant has signed the agreement and money has been collected by company.

1.7. **Extension Facilities** means the electrical facilities, including conductors, cables, transformers, and related equipment installed solely to serve an individual applicant, or groups of applicants. For example, the Extension Facilities to serve a Residential Subdivision would consist of the line extension required to connect the subdivision to Company's existing system, as well as Company's electrical facilities constructed within the subdivision which would include primary and service lines, and transformers.

1.8. **High Rise and/or Mixed-Use Development** means a building built with four or more floors (usually using elevators for accessing floors) or any mixed use development that may consist of either residential or non-residential use or both, such as a building where the first level is for commercial purposes and the upper floors are residential.

1.9. **Irrigation** means water pumping service.

1.10. **Line Extension Agreement** means the contractual agreement between Company and applicant that defines applicant payment requirements, terms of refund, scope of project, estimated costs, and construction responsibilities for Company and the applicant. Line Extension Agreements may be assigned to applicants successors in interest with Company approval, which approval shall not be unreasonably withheld.

1.11. **Master Planned Community Development** means a development that consists of a number of separately subdivided parcels for different Residential Subdivisions. The development may also incorporate a variety of uses including multi-family, non-residential, and public use facilities.

1.12. **Permanent** means a customer who is a tenant or owner of a service location who applies for and receives electric service, which, in the opinion of the Company, is of a permanent and established character. The use of electricity may be continuous, intermittent, or seasonal in nature. Permanency at the service location may be established by such things as city/county/state permits, a permanent water system, an approved sewer/septic system, or other permanent structures.

1.13. **Project-Specific Cost Estimate** means cost estimates that are developed recognizing the unique characteristics of large or special projects to which the Schedule of Charges is not applicable. A Project-Specific Cost Estimate provided to an applicant is valid for a period of up to six (6) months from the date the estimate is provided to the applicant.

1.14. **Residential "Lot Sale" Development** means a tract of land that has been divided into four (4) or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home.

1.15. **Residential Multi-Family Development** means a development consisting of apartments, condominiums, or townhouses.

1.16. **Residential Single Family** means a house, or a manufactured or mobile home Permanently affixed to a lot or site.

1.17. **Residential Subdivision** means a tract of land which has been divided into four (4) or more contiguous lots with an average size of one acre or less in which the developer is responsible for the construction of residential homes or permanent manufactured or mobile home sites.

1.18. **Schedule of Charges** means the list of charges that is used to determine the applicant's cost responsibility for the Extension Facilities. An applicant requesting an extension will be provided a sketch showing the Extension Facilities and an itemized cost quote based on the Schedule of Charges or other applicable details. When the Schedule of Charges is not applicable, charges for Extension Facilities shall be determined by the Company based on Project-Specific Cost Estimates. The Schedule of Charges is attached to this Service Schedule as Attachment 1. The Schedule of Charges will be reviewed and updated from time to time by Company with the Arizona Corporation Commission.

The Schedule of Charges is not applicable for the following:

1.18.1. Extension Facilities requiring modifications, removal, relocations or conversions of existing facilities in conjunction with a new extension or existing customer requested upgrade. The removal, replacement, conversion, and new Extension Facilities charges will be determined by a combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project and may include residual value costs as computed in accordance with the method described in A.R.S 40-347.

1.18.2. Extension Facilities required for modifications, relocations or conversions of existing facilities not in conjunction with a new extension or existing customer upgrade.

1.18.3. Extension Facilities for General Service applicants with estimated demand loads of three (3) megawatts or greater, or that require 3,000 kVA of transformer capacity or greater.

1.18.4. Extension Facilities required for High Rise and/or Mixed-Use Developments or Temporary service.

1.18.5. Extension Facilities involving spot networks, vault installations, primary metering, or specialized or additional equipment for enhanced reliability.

1.19. **Temporary** means premises or enterprises which are temporary in character, or where it is known in advance that the Extension Facilities will be of limited duration.

2. RESIDENTIAL

2.1. SINGLE FAMILY HOMES

Extension Facilities will be installed to new Permanent residential applicants or groups of new Permanent residential applicants under the following conditions:

2.1.1. Free footage basis extensions are made under the following conditions:

2.1.1.1. The total footage of the Extension Facilities (primary, secondary, service) does not exceed 750 feet per applicant, or $10,000; or

2.1.1.2. The total cost of the Extension Facilities as determined by Company is less than $10,000 per applicant.

2.1.2. All additional construction costs over $10,000 per applicant will be paid by applicant(s) as a non-refundable contribution in aid of construction.

2.1.3. Applicants who combine to form a group may also combine their allowance as specified in Sections 2.1.1.1 and 2.1.1.2.

2.1.4. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project which shall exclude the cost of the transformer(s). Construction costs in excess of the allowances as described in 2.1.1.1 and 2.1.1.2 shall be paid by the applicant prior to the Company installing facilities. Payment is due at the time the Line Extension Agreement is signed by the applicant.

2.1.5. The applicant(s) signs a Line Extension Agreement.

2.1.6. The site plan has been approved and recorded in the county having jurisdiction.

2.1.7. The footage allowance of 750 feet and cap of $10,000 shall be reviewed from time to time with the Arizona Corporation Commission.

2.1.8. Examples of the application of 2.1.1 and 2.1.2 can be found in Attachment 2 – Free Footage Illustrative Example.

2.2. RESIDENTIAL SUBDIVISION DEVELOPMENTS

Extension Facilities will be installed to Residential Subdivision developments of four (4) or more homes in advance of application for service by Permanent customers under the following conditions:

2.2.1. The applicant(s) signs a Line Extension Agreement.

2.2.2. The subdivision development plat has been approved and recorded in the county having jurisdiction.

2.2.3. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

2.2.4. A signed Line Extension Agreement and advance payment of all project costs are required prior to the start of construction by the Company. Payment is due at the time the Line Extension Agreement is signed by the applicant.

2.2.4.1. A portion of the project cost shall be designated as a refundable advance and will be eligible for refund based on the "per lot" allowance provisions of Section 2.2.5 and in accordance with Section 5.

2.2.4.2. In lieu of a cash payment for the refundable advance amount, the Company shall reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond based on the financial condition, or organizational structure of developer.

2.2.4.3. That portion of the project cost in excess of the refundable advance shall be non-refundable in addition to any other non-standard construction charges such as street lights.

2.2.5. The refundable advance will be eligible for refund based on a "per lot" allowance of $3,500 for each Permanently connected residential customer over a five (5) year period. Refunds of refundable advances shall be governed by Section 5. The refund eligibility period shall be five (5) years from the date Company executes the Line Extension Agreement with the applicant. A review of the project will be conducted annually to determine subdivision buildout, and if the qualifications have been met for any refunds.

2.2.6. Examples of the application of 2.2.4 can be found in Attachment 3 – Residential Subdivision Illustrative Example.

2.3. RESIDENTIAL "LOT SALE" DEVELOPMENTS

Extension Facilities will be installed to residential "lot sale" developments in advance of application for service by Permanent applicants under the following conditions:

2.3.1. The applicant(s) signs a Line Extension Agreement.

2.3.2. The development plat has been approved and recorded in the county having jurisdiction.

2.3.3. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project. A signed Line Extension Agreement and advance payment of all project costs are

required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

2.3.4. The applicant shall pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for street lights and other non-standard construction charges.

2.3.5. Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required.

2.3.6. Extension Facilities will be installed to individual applicants in accordance with provisions listed in Section 2.1.

2.4. MASTER PLANNED COMMUNITY DEVELOPMENTS

Extension Facilities will be installed to Master Planned Community Developments in advance of application for service by Permanent applicants under the following conditions:

2.4.1. The applicant(s) signs a Line Extension Agreement.

2.4.2. The site development plan has been approved and recorded in the county having jurisdiction.

2.4.3. The cost of extending service to applicant will be determined by a Project-Specific Cost Estimate based on the scope of the project. A signed Line Extension Agreement and advance payment of all project costs are required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

2.4.4. The applicant shall pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for street lights and other non-standard construction charges.

2.4.5. Extension Facilities will be installed to each subdivided tract within the planned development in accordance with the applicable sections of this Service Schedule 3.

2.5. RESIDENTIAL MULTI-FAMILY DEVELOPMENTS

Extension Facilities will be installed to Residential Multi-Family Developments in advance of application for service by Permanent customers under the following conditions:

2.5.1. The applicant signs a Line Extension Agreement.

2.5.2. The site development plan has been approved and recorded in the county having jurisdiction.

2.5.3. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost estimate depending on the scope of the project.

2.5.4. A signed Line Extension Agreement and advance payment of all project costs are required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

2.5.4.1. A portion of the project cost shall be designated as a refundable advance and will be eligible for refund based on the "per unit" refundable allowance provisions of Section 2.5.4 and in accordance with Section 5.

2.5.4.2. In lieu of a cash payment for the refundable advance amount, the Company shall reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond based on the financial condition, or organizational structure of applicant.

2.5.4.3. That portion of the project cost in excess of the refundable advance shall be non-refundable in addition to any other non-standard construction charges such as street lights etc.

2.5.5. The refundable advance will be eligible for refund based on a "per unit" allowance of $1,000 for each new meter installed over a five (5) year period. Refunds of refundable advances shall be governed by Section 5. The refund eligibility period shall be five (5) years from the date Company executes the Line Extension Agreement. A review of the project will be conducted annually to determine buildout and if the qualifications have been met for any refunds.

3. GENERAL SERVICE INCLUDING IRRIGATION

3.1. GENERAL PROVISIONS

3.1.1. Extension Facilities that do not meet the requirements under Section 2 Residential will be considered General Service and will be installed to all applicants who meet the qualifications under Sections 3 and 4 of this Service Schedule 3.

3.1.2. The project costs for General Service Extension Facilities installations will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project. A signed Line Extension Agreement and any required payment as determined by an Economic Feasibility analysis are required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant. The site development plan for the project for which the Line Extension has been requested must be approved and recorded in the county having jurisdiction prior to signing the Line Extension Agreement.

3.1.3. The cost for Extension Facilities installed for applicants with estimated demand loads of less than three (3) megawatts or less than 3,000 kVA of transformer capacity, will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project. A signed Line Extension Agreement and any required payment as determined by an Economic Feasibility analysis are required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

3.1.4. The cost for Extension Facilities installed for applicants with projected loads of three (3) megawatts or greater, requiring transformer capacity of 3,000 kVA and greater, special requests involving primary metering, or specialized/additional equipment for enhanced reliability shall be determined by the Company based on Project-Specific Cost Estimates. A signed Line Extension Agreement and any required payment as determined by an Economic Feasibility analysis are required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

3.1.5. Economic Feasibility analysis for General Service applicants:

3.1.5.1. Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is $25,000 or less shall be established where the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) multiplied by six (6) is equal to or greater than the cost of the applicant's Extension Facilities.

3.1.5.2. Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 shall be established where the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

3.1.5.3. Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

3.2. HIGH RISE AND/OR MIXED-USE DEVELOPMENTS

Extension Facilities will be installed to High Rise and/or Mixed-Use Developments in advance of application for service by Permanent applicants under the following conditions:

3.2.1. The residential units are privately owned and either individually metered or master metered in accordance with Section 7.10.

3.2.2. Extension Facilities will be installed to designated points of delivery and it is the applicant's responsibility to provide and maintain the electrical facilities within the building.

3.2.3. The applicant signs a Line Extension Agreement.

3.2.4. The site development plan has been approved and recorded in the county or city having jurisdiction.

3.2.5. The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate, and shall be paid by the applicant prior to Company installing facilities.

3.2.6. Prior to the ordering of specialized materials or equipment required to provide service applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 7.13 of this Service Schedule 3.

3.2.7. A signed Line Extension Agreement and any required advance payment are required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

3.3. CORPORATE BUSINESS & INDUSTRIAL PARK DEVELOPMENTS

Extension Facilities will be made to Corporate Business and Industrial Park Developments in advance of application for service by Permanent customer under the following conditions:

3.3.1. The applicant signs a Line Extension Agreement.

3.3.2. The site development plan has been approved and recorded in the county or city having jurisdiction.

3.3.3. The cost of installing Extension Facilities will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a project-specific cost estimate depending on the scope of the project.

3.3.4. The applicant shall pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for street lights and other non-standard construction charges.

3.3.5. Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

3.3.6. Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required.

3.3.7. Extension Facilities will be installed to individual lots (at the request of an applicant) within the Corporate Business and Industrial Park Development in accordance with the applicable sections of this Service Schedule 3.

4. OTHER CONDITIONS

4.1. TEMPORARY APPLICANTS

4.1.1. Where Temporary Extension Facilities are required to provide service to the applicant, the applicant shall make a non-refundable payment in advance of installation or construction equal to the cost of installing and removing of the facilities required in providing Temporary service, less the salvage value of such facilities. Charges will be determined by Company based on a Project-Specific Cost Estimate. Payment is due at the time the Line Extension Agreement is signed by the applicant.

4.1.2. When use of the Temporary service is discontinued or service is terminated, Company may dismantle and remove its facilities, and the materials and equipment provided by Company will remain Company property.

4.2. DOUBTFUL PERMANENCY CUSTOMERS

When, in the opinion of Company, permanency of the applicant's residence or operation is doubtful, the applicant will be required to pay the total cost of the Extension Facilities. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate. The applicant shall pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for street lights and other non-standard construction charges.

4.2.1. Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

4.3. MUNICIPALITIES AND OTHER GOVERNMENTAL AGENCIES

Relocation of existing facilities and/or Extension Facility installations required to serve loads of municipalities or other governmental agencies may be constructed prior to the receipt of a signed Line Extension Agreement. However, this does not relieve the municipality or governmental agency of the responsibility for payment of the Extension Facilities costs in accordance with the applicable sections of this Service Schedule 3.

The effective date for projects enacted under this provision for purposes of Section 5 shall be the date the municipality or agency provided written approval to the Company to proceed with construction.

5. REFUNDS

5.1. GENERAL REFUND CONDITIONS

5.1.1. No refund will be made to any applicant for an amount more than the un-refunded balance of the applicant's refundable advance.

5.1.2. Company reserves the right to withhold refunds to any applicant who is delinquent on any account, agreement, or invoice, including the payment of electric service, and may apply these refund amounts to past due bills.

5.1.3. The refund eligibility period shall be five (5) years from the date Company executes the Line Extension Agreement with the applicant. Any un-refunded advance balance shall become a non-refundable contribution in aid of construction five (5) years from the Execution Date of the agreement.

5.1.4. Refunds will be mailed to the applicant of record noted on the executed agreement no later than 60-days from the annual review date.

6. UNDERGROUND CONSTRUCTION

6.1. GENERAL UNDERGROUND CONSTRUCTION POLICY

With respect to all underground installations pursuant to a Line Extension Agreement, Company will install underground facilities only if all of the following conditions are met:

6.1.1. The Extension Facilities meet all requirements as specified in Sections 1, 2, 3, or 4 of this Service Schedule 3.

6.1.2. The applicant provides all earth-work including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications, and signs a trench agreement.

6.1.3. The applicant provides installation of equipment pads, pull-boxes, manholes, conduits, and appurtenances as required and in accordance with Company specifications.

6.1.4. In lieu of applicant providing these services and equipment, the applicant may pay Company to provide these services and equipment as a non-refundable contribution in aid of construction. The payment will equal the cost of such work plus any administrative or inspection fees incurred by Company. Applicants electing this option will be required to sign an agreement indemnifying and holding Company harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other than Company's contractors, which Claims arise out of the trenching and conduit placement, provided the Claims are not attributable to the Company's gross negligence or intentional misconduct.

7. GENERAL CONDITIONS

7.1. VOLTAGE

7.1.1. All Extension Facility installations will be designed and constructed for operation at standard voltages

used by Company in the area in which the Extension Facilities are located. At the request of applicant, Company may, at its option, deliver service for special applications of non-standard or higher voltages with prior approval from Company's Engineering Department. Applicant will be required to pay the costs of any required studies as a non-refundable payment.

7.1.2. Extension Facilities installed at higher voltages will be limited to serving an applicant operating as one integral unit under the same name and as part of the same business on adjacent and contiguous sites not separated by private property owned by another party or separated by public property or public right–of- way.

7.2. POINT OF DELIVERY

7.2.1. For overhead service, the point of delivery shall be where Company's service conductors terminate at the applicant's weatherhead or bus riser.

7.2.2. For underground service, the point of delivery shall be where Company's service conductors terminate in the applicant's or development's service equipment. The applicant shall furnish, install and maintain any risers, raceways and/or termination cabinets necessary for the installation of Company's underground service conductors.

7.2.3. For special applications where service is provided at voltages higher than the standard voltages specified in the APS Electric Service Requirements Manual, Company and applicant shall mutually agree upon the designated point of delivery.

7.3. EASEMENTS

All suitable easements or rights-of-way required by Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the applicant or other property required for the Extension Facilities, shall be provided to the Company in Company's name by the applicant without cost to or condemnation by Company prior to commencement of Company's construction of Extension Facilities. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

7.4. GRADE MODIFICATIONS

If after construction of Extension Facilities, the final grade of the property established by the applicant is changed in such a way as to require relocation of Company facilities, or the applicant's actions or those of his contractor results in damage to such facilities, the cost of replacement, relocation and/or resulting repairs shall be borne by applicant as a non-refundable contribution in aid of construction.

7.5. OWNERSHIP

Except for applicant owned facilities, all Extension Facilities installed in accordance with this Service Schedule 3 will be owned, operated, and maintained by Company.

7.6. MEASUREMENT AND LOCATION

7.6.1. Measurement must be along the proposed route of construction.

7.6.2. Construction will be on public streets, roadways, highways, or easements acceptable to Company.

7.6.3. The Extension Facilities must be a branch from, the continuation of, or an addition to, Company's existing distribution facilities.

7.7. UNUSUAL CIRCUMSTANCES

In unusual circumstances as determined by Company, when the application and provisions of this Service Schedule 3 appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when applicant's estimated demand load will exceed 3,000 kW, Company may make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in the Company's Service Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

7.8. ABNORMAL LOADS

Company, at its option, may install Extension Facilities to serve certain abnormal loads (such as: transformer type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics) and the costs of any distribution system modifications or enhancements required to serve the applicant will be included in the payment described in previous sections of this Service Schedule 3.

7.9. UPGRADES, RELOCATIONS AND/OR CONVERSIONS

7.9.1. Company will upgrade, relocate or convert from overhead to underground its facilities for the applicant's convenience or aesthetics. The cost of upgrades, relocations or conversions not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate and may include residual value costs as computed in accordance with the method described in A.R.S Section 40-347.

7.9.2. When the relocation of Company facilities involves "prior rights" conditions, the applicant will be required to make payment equal to the estimated cost of relocation as determined by a Project-Specific Cost Estimate. In addition applicant shall be required to provide similar "rights" for the relocated facilities.

7.10. MASTER METERING

7.10.1. Mobile Home Parks

Company shall refuse service to all new construction and/or expansion of existing Permanent residential mobile home parks unless the construction and/or expansion are individually metered by Company.

7.10.2. Residential Apartment Complexes, Condominiums

Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Arizona Corporation Commission's Rules and Regulations or the requirements discussed in 7.10.3 below. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.

7.10.3. Multi-Unit High Rise Residential Developments

7.10.3.1. Company will allow master metering for high rise residential units where the residential units are privately owned provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

7.10.3.2. Sub-metering shall be provided and maintained by the builder or homeowners association.

7.10.3.3. Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company installing Extension Facilities.

7.10.3.4. Company will convert its facilities from a master metered system to a Permanent individually metered system at the applicant's request provided the applicant makes a non-refundable contribution in aid of construction equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended on the basis specified in Section 1 of this Service Schedule 3. Applicant is responsible for all costs related to the installation of new service entrance equipment.

7.11. CHANGE IN APPLICANT'S SERVICE REQUIREMENTS

Company will rebuild, modify, or upgrade its existing facilities to meet the applicant's added load or change in service requirements on the basis specified in Section 2, 3, or 4. Charges for such changes will be in accordance with the Schedule of Charges and/or a Project-Specific Cost Estimate determined by the Company based on project-specific requirements.

7.12. STUDY AND DESIGN AGREEMENT

Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates will be required to make a payment to Company in an amount equal to the estimated cost of preparation. When the applicant authorizes Company to proceed with construction of the Extension Facilities, the payment will be credited to the cost of the Extension Facilities otherwise the payment shall be non-refundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the applicant upon request.

7.13. MATERIAL ORDER AGREEMENT

Any applicant requesting Company to enter into a Line Extension Agreement, or relocation agreement which requires either large quantities of material or material and equipment which the Company does not keep in stock will be required to make a payment to Company prior to the material being ordered in an amount equal to the material/equipment's estimated cost. When the applicant authorizes Company to proceed with construction of the extension, the payment will be credited to the cost of the extension; otherwise the payment shall be non-refundable.

7.14. INTEREST

All refundable advances made by the applicant to the Company shall be non-interest bearing.

7.15. APPLICANT CONSTRUCTION OF COMPANY DISTRIBUTION FACILITIES

7.15.1. Applicant may provide construction related labor only services associated with the installation of new distribution line facilities (21 kV and below) to serve the applicant's new or added load provided the applicant receives written approval from Company prior to performing any such services and uses electrical contractors who are qualified and licensed in the State of Arizona to construct such facilities and designated as an APS Approved Electrical Distribution Contractor.

This option is not available for the following:

7.15.1.1. Replacement, modifications, upgrades, relocation, or conversions of existing systems.

7.15.1.2. Where all or a portion of the distribution line facilities are to be constructed on or installed on existing distribution line or transmission lines.

7.15.2. All construction services provided by the applicant shall be subject to inspection by a duly authorized Company representative and shall comply with Company designs, construction standards, and other requirements which may be in effect at the time of construction. Any work found to be substandard in the sole opinion of the Company must be corrected by applicant prior to energization by Company.

7.15.3. Applicant shall reimburse Company for all inspection and project coordination costs as a non-refundable contribution in aid of construction. Estimated costs for inspection and project coordination will be identified in the construction agreement executed by Company and applicant.

7.15.4. Costs for Extension Facilities for applicants who provide construction of Company distribution facilities shall be based on a Project-Specific Cost Estimate.

7.15.5. A signed agreement and advance payment of all project costs are required prior to the start of applicant construction. Payment is due at the time the agreement is signed by the applicant.

7.15.6. For applicants that are not served by the terms in Section 3 of this document, Company shall provide a Project-Specific Cost Estimate. Applicants may submit an invoice detailing costs of Extension Facilities and apply any allowance provided in Section 2 to these costs. At no point shall these costs exceed the Company's Project-Specific Cost Estimate.

7.15.7. Applicants served by the terms in Section 3 of this document shall be subject to the rules set forth in Sections 3 and 5.

7.16. SETTLEMENT OF DISPUTES

Any dispute between the applicant or prospective applicant and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may, by either party, be referred to the Arizona Corporation Commission or a designated representative or employee thereof for determination.

7.17. LINE EXTENSION AGREEMENTS

All facility installations or equipment upgrades requiring payment by an applicant shall be in writing and signed by both the applicant and Company.

7.18. ADDITIONAL PRIMARY FEED OR SPECIALIZED EQUIPMENT

When specifically requested by an applicant to provide an alternate primary feed or specialized equipment (excluding transformation), Company will perform a special study to determine the feasibility of the request. The applicant will be required to pay for the cost of the additional feed requested as a non-refundable contribution in aid of construction. Installation cost will be based on a Project-Specific Cost Estimate. Payment for the installation of Extension Facilities is due at the time the Line Extension Agreement is signed by the applicant.

7.19. GRANDFATHERING

An applicant that has entered into a Line Extension Agreement with the Company under a previous revision of this Service Schedule 3 may at applicant's request cancel the agreement, provided the Company has not installed any facilities pursuant to the agreement, and provided that applicant reimburses Company for the costs and expenses it has incurred to date, as a non-refundable contribution in aid of construction. The applicant may then enter into a new Line Extension Agreement with the Company under this revision of Service Schedule 3.

Attachment 1
Schedule of Charges – Single Phase

APS Schedule 3, Line Extension Schedule of Charges
Single Phase Extension Costs

	OH Primary	UG Primary				OH Secondary	UG Secondary	
Single Phase	Cost per Circuit Foot	Cost per Circuit Foot	Pull Box	Pad Mount Junction Cabinet	OH/UG Transition	Secondary Pole	OH/UG Secondary Transition	J Box
	$15.00	$6.00	$705	$2,682	$1,183	$2,339	$681	$98.54
OVERHEAD Single Phase	**SES Size**	**Transformer Size, 120/240V**		**Service wire/Linear Ft**				
	200 Amp	25kVA	$3,657	$4.89				
	200 Amp	50kVA	$4,439	$9.02				
	400 Amp	50kVA	$4,439	$9.02				
	600 Amp	75kVA	$5,475	$18.23				
	800 Amp	100kVA	$7,699	$18.23				
UNDERGROUND Single Phase	**SES Size**	**Transformer Size, 120/240V**		**Service wire/Linear Ft**				
	200 Amp	25kVA	$3,764	$3.65				
	200 Amp	50kVA	$4,498	$4.36				
	400 Amp	50kVA	$4,498	$4.36				
	600 Amp	75kVA	$5,266	$8.71				
	800 Amp	100kVA	$6,270	$16.68				

Notes:
1) Extension Facilities that do not qualify for the Schedule of Charges will be determined by a project specific cost estimate.
2) Cost per foot charges will be determined from termination at the source to the next device in the circuit. Linear footage for each circuit will be summed to determine charges.
3) Pad Mount switch gear is a single phase termination cabinet.
4) Primary OH cost per foot is for one phase and a neutral or two phases and no neutral, includes poles, framing, 2R conductor
5) Charges for services are based on linear feet from Transformer to SES regardless of the number of sets. J Boxes not included in footage cost.
6) All footages to be calculated by linear footages
7) Transition is from the OH line to the UG line, which includes wire down pole and accessories. Pole NOT included.

Attachment 1
Schedule of Charges – Three Phase

APS Schedule 3, Line Extension Schedule of Charges
Three Phase Extension Costs

FEEDER Three Phase	Overhead	Underground								
	Cost per Circuit Foot	Cost per Circuit Foot (3-750)	Pull Box (3-750)	Manhole (3-750)	Cost per Circuit Foot (6-750)	Pull Box (6-750)	Manhole (6-750)	Pad Mount Switch Gear	Cost per Circuit Foot 1100A Cable (3-1100)	Cost per Circuit Foot 1100A Cable (6-1100)
	$31.34	$24.03	$3,575	$10,522	$48.06	$6,164	$14,033	$16,648	$32.35	$64.70
		Each Installation			Each Installation				Each Installation	Each Installation
OH/UG Transition		$6,701			$8,290				$7,050	$8,987
	Overhead	Underground								
PRIMARY Three Phase	Cost per Circuit Foot	Cost per Circuit Foot (3-1/0T)	Cost per Circuit Foot (3-4/0T)	Pull Box	Pad Mount Switch Gear					
	$21.24	$17.97	$28.81	$1,257	$16,648					
		Each Installation	Each Installation							
OH/UG Transition		$2,796	$2,933							
OVERHEAD Three Phase	Overhead									
	SES Size	Transformer Size 120/208 Volts		Service wire/Linear Ft		SES Size	Transformer Size 277/480 Volts		Service wire/Linear Ft	
	200 Amp	3-25kVA	$9,979	$5.41		200 Amp	3-50kVA	$13,215	$5.41	
	200 Amp	3-50kVA	$12,728	$5.41						
	400 Amp	3-50kVA	$12,728	$9.87		400 Amp	3-75kVA	$15,844	$9.87	
	600 Amp	3-50kVA	$12,728	$19.75		600 Amp	3-100kVA	$18,945	$19.75	
UNDERGROUND Three Phase	Underground Pad mount									
	SES Size	Transformer Size 120/208 Volts		Service wire/Linear Ft		SES Size	Transformer Size 277/480 Volts		Service wire/Linear Ft	
	200 Amp	112.5kVA	$11,746	$6.33		200 Amp	112.5kVA	$11,852	$6.33	
						400 Amp	150kVA	$12,213	$12.66	
	400 Amp	112.5kVA	$11,746	$12.66		400 Amp	225kVA	$14,804	$12.66	
	600 Amp	150kVA	$13,316	$15.54		600 Amp	300kVA	$17,539	$12.66	
	800 Amp	225kVA	$15,022	$31.07		800 Amp	500kVA	$19,519	$31.07	
	1000 Amp	225kVA	$15,022	$31.07		1000 Amp	500kVA	$19,519	$31.07	
	1200 Amp	300kVA	$18,110	$31.07		1200 Amp	750kVA	$25,392	$46.61	
	1600 Amp	500kVA	$22,432	$62.15		1600 Amp	1000kVA	$27,129	$62.15	
	2000 Amp	500kVA	$22,432	$62.15		2000 Amp	1000kVA	$27,129	$62.15	
	2500 Amp	750kVA	$28,233	$108.72		2500 Amp	1500kVA	$42,414	$93.22	
	3000 Amp	750VA	$28,233	$108.72		3000 Amp	1500KVA	$42,414	$93.22	
	3000 Amp	1000kVA	$37,272	$139.86		3000 Amp	2000KVA	$52,748	$139.86	

Notes:

1) Extension Facilities that do not qualify for the Schedule of Charges will be determined by a project specific cost estimate.
2) Cost per foot charges will be determined from termination at the source to the next device in the circuit. Linear footage for each circuit will be summed to determine charges.
3) For Multiple services out of one three phase transformer; the service cost will be determined by each SES and the transformer cost will be determined from the combined total of each SES size in amps, rounded up to the nearest SES size, limited to a combined maximum of 3,000. amps.
4) Overhead feeder cost per foot is for 3/0 and above, including 477 & 795 conductors.
5) UG Feeder circuit footage is 3 cables making up 3 phase; 2 circuits is parallel conductors.
6) Charges for services are based on linear feet from transformer to SES regardless for the number of sets.
7) All footages to be calculated by linear footages
8) Transition is from the OH line to the UG line, which includes wire down pole and accessories. Pole NOT included.

Examples to Section 2.1*
Free Footage Illustrative Example

	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 1	**500**	**$15.00**	**50**	**$ 4.89**	**550**	**$ 7,744.50**	**$ -**

APS $7,744.50** ⟷ Total 550' ⟷ Customer Payment $0

	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 2	**620**	**$ 15.00**	**135**	**$ 4.89**	**755**	**$ 9,960.15**	**$ -**

APS $9,960.15** ⟷ Total 755' ⟷ Customer Payment $0

	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 3	**675**	**$ 15.00**	**50**	**$ 4.89**	**725**	**$ 10,369.50**	**$ 369.50**

APS $10,000.00** ⟷ Total 725' ⟷ Customer Payment $369.50

	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 4	**660**	**$ 15.00**	**90**	**$ 4.89**	**750**	**$ 10,340.10**	**$ 340.10**

APS $10,000.00** ⟷ Total 750' ⟷ Customer Payment $340.10

	Primary		Service		Total		Customer
	Footage	Cost	Footage	Cost	Footage	Cost	Payment
Scenario 5	**700**	**$ 15.00**	**100**	**$ 4.89**	**800**	**$ 10,989.00**	**$ 989.00**

APS $10,000.00** ⟷ Total 800' ⟷ Customer Payment $989.00

*Scenarios do not reflect all components required for a complete project.
**APS portion does not include cost of transformer.

Attachment 3
Residential Subdivision Illustrative Example

Scenario 1	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 2	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 3	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

Scenario 4	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

Schedule 4

SERVICE SCHEDULE 4: TOTALIZED METERING OF MULTIPLE SERVICE ENTRANCE SECTIONS AT A SINGLE SITE FOR STANDARD OFFER AND DIRECT ACCESS SERVICE

Arizona Public Service Company (Company) customers at a single site whose load requires multiple points of delivery through multiple service entrance sections (SESs) may be metered and billed from a single meter through Adjacent Totalized Metering or Remote Totalized Metering as specified in this schedule.

Totalized Metering (Adjacent or Remote) is the measurement for billing purposes on the appropriate rate, through one meter, of the simultaneous demands and energy of a customer who receives electric service at more than one SES at a single site.

A. Totalized metering will either be Adjacent or Remote and shall be permitted only if conditions 1 through 8 are all satisfied.

1. The customer's facilities must be located on adjacent and contiguous sites not separated by private or public property or right-of-way and must be operated as one integral unit under the same name and as a part of the same business or residence (these conditions must be met to be considered a single site, as specified in Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service, Section 4.1.1); and

2. Power will generally be delivered at no less than 277/480 volt (nominal), three phase, four wire or 120/240 volt (nominal) single phase three wire; and

3. Three phase and single phase service entrance sections can not be combined for totalizing purposes; and

4. For Standard Offer customers, totalized metering may be accomplished by providing electronically totalized demand and energy reads or by means of a physical wire interconnection of metering information with the customer providing conduit between the SESs; for Direct Access customers the customer's Electric Service Provider may provide electronically totalized demand and energy reads in compliance with Company's Schedule 10, Terms and Conditions for Direct Access; and

5. The customer shall provide vault or transformer space, which meets Company specifications, on the customer's property at no cost to Company; and

6. If the customer operates an electric generation unit on the premise, totalized metering will be permitted when the customer complies with all of Company's requirements for interconnection, pays all costs for any additional special metering required to accommodate such service from totalized service sections, and takes service on an applicable rate schedule for interconnected customer owned generation; and

7. Written approval by Company's authorized representative is required before totalized metering may be implemented.

8. Customers electing to have accounts either Adjacent or Remote Totalized metered will be required to maintain the accounts in the approved totalized configuration for a minimum of one (1) year.

B. Adjacent Totalized Metering will apply when conditions A.1-A.8 and the following conditions are met:

1. The customer's <u>total</u> load to be totalized requires a National Electrical Code (NEC) service entrance size of over 3,000 amps three phase or 800 amps single phase; and

2. Company requires that load be split and served from multiple SESs; and

3. The customer must locate SESs to be totalized within 10 feet of each other.

There will be no additional charge to the customer's monthly bill for Adjacent Totalized Metering.

C. Remote Totalized Metering will apply when conditions A.1-A.8 are met, multiple SESs are separated from one another by more than 10 feet, and the following conditions are met:

1. Each of the customer's service entrance sections to be totalized requires an NEC section size of 3,000 amps three phase or 800 amps single phase or greater; and

2. The customer's total load to be totalized has a minimum demand of 2,000 kVa or 1,500 kW three phase or 100 kVa or 80 kW single phase; and

3. The customer has made a non-refundable contribution for the net additional cost to Company of the meter totalizing connection and equipment.

When the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is equal to or less than the cost to serve a single point of delivery, then no additional monthly charge shall be made to the customer receiving Remote Totalized Metering. However, lower capital investment which results from the customer's contribution, other than the meter costs in C.3 above, shall not be considered.

For customers where the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is greater than the cost to serve at a single point of delivery, then there shall be an additional charge. The additional monthly charge for each delivery point above one shall consist of 1% of the totalized bill, plus $500.00, plus all applicable taxes and adjustments.

D. Removal of Totalized Metering Configuration

In some cases, it may be to the customer's benefit to remove all totalized metering equipment, or remove selected totalized metering equipment from the totalized account. This will be permitted under the following conditions:

1. The customer must submit a written request to Company stating the reason for the removal and the specific equipment to be removed.

2. After removal of the equipment, the customer may not ask for services to be totalized for one (1) year from the removal date. At the end of one (1) year, if the customer does request services to be totalized, the applicable conditions listed above must be met.

3. The customer will be required to make a nonrefundable contribution for the costs associated with the removal of the meter totalizing connection and equipment.

4. In the event the customer should elect to remove a meter from a totalized metering configuration, the customer will continue to be responsible for the minimum billing kW parameters noted on the Customer's Electric Supply Agreement.

5. Customer may elect an alternate rate schedule for accounts that are removed from the totalized configuration however no further rate schedule changes may be made within the succeeding twelve (12) month period in accordance with the provisions of the Company's Schedule 1.

Schedule 5

1. Arizona Public Service Company (Company) shall have no liability of obligation for claims arising out of the procedures for curtailment or interruption of electric service effected by it in accordance with such guidelines or such supplemental, amendatory or implementary guidelines or regulations as may hereafter be established and as provided by law.

2. Company shall endeavor to identify any electric customer(s) who might be classified as having either essential or critical loads. In the event that any customer of Company is dissatisfied by the classification of Customer by Company, or with the amount of such customer's load (if any) classified by the Company as critical or essential, the Customer may bring the matter to either the Company or the Commission and request a determination in regard thereto. However, until such redetermination is made by the Commission or the Company, customer's original classification for purposes of electric curtailment under this Schedule shall be unaffected.

3. Company shall endeavor to, as circumstances permit and as further discussed in the Company's detailed Electric Load and Curtailment Plan, to notify County emergency personnel, or similar local authorities, of existing or developing situations involving the curtailment or interruption of APS customers pursuant to this Schedule #5.

4. DEFINITIONS

   4.1 Essential Loads – Loads necessary to serve facilities used to protect the health and safety of the public, such as: hospitals, 911 Centers, national defense installations, sewage facilities and domestic water facilities. Loads necessary to serve 911 Centers, police stations, and fire stations, which do not have independent back-up generation and require APS' electric service for operation of essential emergency equipment.

   4.2 Critical Loads – That portion of the electric load of nonresidential customers, which in the event of 100 percent curtailment of service, would cause excessive damage to equipment or material being processed, or where such interruption would create grave hazards to employees or the public.

   4.3 Major Use Customers/Others (With Notice) – Those customers having relatively large loads (over 1000 kW) or a substantial number of employees or other special circumstances that make it appropriate to schedule blackouts or curtailments different from typical customers. Customers who qualify as Major Use/Others (With Notice) can take 100 percent curtailment when sufficient notice is provided. These loads will be interrupted after the required notification period. "Sufficient", "required", and "appropriate" notice is that notice that APS, after consultation with the affected customer, has determined will allow the customer to curtail in a safe and efficient manner. Such notice necessarily varies from customer to customer.

   4.4 Others (With or Without Notice) – All customers not meeting the above definitions. These customers will be interrupted (with or without notice) if voluntary curtailment measures are not sufficient to alleviate the situation.

5. GUIDELINES TO BE APPLICABLE IN EVENT OF INTERRUPTION OR CURTAILMENT OF ELECTRIC SERVICE BY COMPANY TO ITS CUSTOMERS DUE TO POWER SUPPLY INTERRUPTIONS, FUEL SHORTAGE OR TRANSMISSION EMERGENCY PURSUANT TO CORPORATION COMMISSION RULE R14-2-208, PROVISION OF SERVICE, PARAGRAPH E.

   5.1 Operating Procedures Prior to Customer Load Curtailment

5.1.1 The following items shall be pursued concurrently

5.1.1.1 Reschedule maintenance of transmission components and generating units, where practical.

5.1.1.2 Utilize spinning reserve.

5.1.1.3 Discontinue all non-firm wholesale sales during any period of involuntary curtailment or when an involuntary curtailment is anticipated.

5.1.1.4 Do not enter into any new wholesale sales during any period of involuntary curtailment or when an involuntary curtailment is anticipated.

5.1.1.5 Start all standby units.

5.1.1.6 Contact other utilities and/or agencies for emergency assistance.

5.1.1.7 Invoke emergency and short-term contractual schedules with other utilities and/or agencies.

5.1.1.8 Reduce system voltage, where practical.

5.1.1.9 Reduce non-essential Company uses such as flood lighting, sign lighting, display lighting, office lighting, electric cooling and heating, etc., where practical.

5.1.1.10 Provide information through the media or other appropriate medians to the public which will contain instructions on how customers can assist Company in case of an emergency power outage.

5.1.1.11 Work with government agencies and environmental groups to seek waivers on environmental constraints and/or expedite permitting process for company-owned generation, as well as, customer generation, as appropriate.

5.2 Voluntary Customer Load Curtailment

5.2.1 Public Appeal

5.2.1.1 An advisory message procedure will be used when Company has advance indications that it will not be able to meet future peak loads. These messages will request voluntary load reduction during specific hours on specific days.

5.2.1.2 An emergency bulletin procedure will be used for instant notification to the public in the event there is no advance indication of a power shortage. These bulletins will request the immediate voluntary cooperation of all customers in reducing electric loads.

5.2.1.2.1 These bulletins will request all customers to reduce the use of all electrically operated equipment and devices, where possible.

5.2.1.2.2 Company will have a prepared statement to read which will give current information on the Power Supply Interruption, Fuels Shortage or Transmission Emergency.

5.3 Contractually Interruptible Load

5.3.1 Company shall invoke contractual interruption provisions to the extent appropriate.

5.3.2 Company shall interrupt non-firm wholesale customer(s) as appropriate.

5.4 Involuntary Customer Load Curtailment

5.4.1 If the load reduction realized from application of the voluntary curtailment procedures is not sufficient to alleviate the power shortage, Company will reduce voltage if and to the extent practical and in accordance with normal applicable electric utility operation standards.

5.4.2 If further load reduction is required, load will be reduced as follows:

5.4.2.1 Circuits not classified with "Major Use/Others With Notice, Critical or Essential" customers will be interrupted on a rotating basis. The frequency and duration of such interruptions will be dependent upon the magnitude and nature of the power shortage. The frequency and duration of such interruptions shall also consider the circumstances of Major Use Customers.

5.4.2.2 Accurate records will be kept to ensure that these circuits are rotated in an equitable and technically feasible manner.

5.4.2.3 Circuits classified as "Major Use/Others" will be interrupted upon the giving of appropriate notice.

5.4.2.4 Customers on circuits which serve critical loads will be required to curtail the non-critical portion of their loads. Thereafter, circuits which serve critical loads will be identified and will not be interrupted unless an area must be dropped to maintain stability of the electric system. However, loads otherwise classifiable as critical may be curtailed if they possess back-up generation sufficient to meet their entire load requirement. If a customer having a critical load refuses or fails to curtail his electric consumption down to the critical load, he shall thereupon not be considered to have a critical load for purposes of this Schedule.

5.4.2.5 Circuits which serve essential loads will be identified and will not be interrupted unless an area must be dropped to maintain stability of the electric system. However, loads otherwise classifiable as essential may be curtailed if they possess back-up generation sufficient to meet their entire load requirement.

5.5 Sudden Shortages of Power

In the event that time does not allow for the implementation of the Electric Curtailment Guidelines, Company may resort to its emergency operations procedures, with or without notice.

5.6 Automatic Load Shedding

In the event that there is a major electrical disturbance threatening the interconnected Southwest system with blackout conditions, emergency devices such as under frequency load shedding, transfer tripping, etc., will be utilized to maintain the optimum system stability.

6. ELECTRIC CURTAILMENT OF FIRM WHOLESALE CUSTOMERS

6.1 The term "firm wholesale customer" shall be defined as those APS customers who purchase, on a firm basis, electricity from the Company for purposes of resale.

6.2 In any given instance where a curtailment of wholesale power deliveries is involved, and subject to any required approvals of the Federal Energy Regulatory Commission or contractual provisions to the contrary, Company shall notify its firm wholesale customers, requesting that they curtail electric service to their retail customers during the period that Company's system is affected by power shortages. In the event that Company is unable to obtain the cooperation of a firm wholesale customer, it may seek an order from appropriate governmental authority requiring the firm wholesale customer to accept a reduction of electricity deliveries proportionate to the curtailment being effected on Company's system.

7. ELECTRIC LOAD AND CURTAILMENT PLAN

A detailed electric load and curtailment plan shall be kept on file with the Arizona Corporation Commission. This plan shall contain specific procedures for implementation of the above, along with the name(s) and telephone number(s) of the appropriate Company personnel to contact in the event implementation of the plan becomes necessary. This plan shall be updated at least annually, and it or amendments thereto shall become effective upon submission to the Arizona Corporation Commission.

7.1 Company shall contact the Director, Utilities Division, or their designee, as soon as practical for any curtailment pursuant to this Schedule #5.

Schedule 6

1. APPLICABILITY

1.1 The services, provisions and fees in this schedule shall apply to an entity (Developer) desiring to interconnect a generating facility to the Arizona Public Service (APS or Company) power delivery system that is not otherwise subject to the Federal Energy Regulatory Commission (FERC) interconnection processes or rules. *See* 18 C.F.R. § 292.306; *Western Massachusetts Electric Co.*, 61 FERC ¶61,182 at p. 61,661-62 (1992), *aff'd* 165 F.3d 922, 926 (D.C. Cir. 1999).

1.2 This schedule shall only apply to a Qualifying Facility as defined in 18 C.F.R. § 292.203, for which the total generation output that is transmitted to the APS power delivery system is sold directly to APS.

1.3 This schedule shall not apply to a generating facility that is interconnected on the load side of an APS retail customer's meter and is primarily intended to serve the customer's electricity requirements, including, for example, a net metering facility as defined in A.A.C. R14-2-2302.

2. DESCRIPTION OF SERVICES

2.1 Feasibility Study - APS will conduct a preliminary review of the potential impacts of the proposed generating facility on the APS power delivery system. The study will assess the expected capacity requirements of the proposed generator on the delivery system compared with the available system capacity at the point of interconnection and identify any potential overload issues for the delivery system and circuit protection devices. Additionally, this study will provide an initial assessment of the complexity and likely costs for the interconnection.

2.1.1 The Developer shall identify the proposed project site location prior to commencement of the study.

2.1.2 Although the Feasibility Study is optional, no system impact or cost information will be provided by APS without the study and associated fee.

2.2 System Impact Study - APS will conduct a full technical review of the project's impact on the APS power delivery system, including power flow, APS system protective device coordination, system protection schemes and voltage drop. This study will determine if any upgrades to APS's system are required to build and interconnect the project as designed.

2.2.1 Although the System Impact Study is optional, no related information will be provided by APS without the study and fee.

2.3 Facilities Study - APS will conduct a comprehensive analysis of the actual construction requirements for the APS power delivery system, based on the information from the Feasibility Study and System Impact Study or equivalent information provided by the Developer or third party. The study shall provide the detailed costs of construction and milestones associated with the requirements.

2.3.1 This study is required for interconnection to the Company's power delivery system.

2.4 All services in this schedule are distinct from any similar-termed services provided by APS under FERC interconnection processes, which are not governed by this schedule.

3. FEES

3.1 Feasibility Study - $5,000 per study.

3.2 System Impact Study - $15,000 per study. Fee shall be reduced to $10,000 if a Feasibility Study has been completed by APS for the specific project.

3.3 Facilities Study - $100 per hour. The total fee shall be reduced by any payments received under subsections 3.1 and 3.2 for the specific project, where the net amount shall not be less than zero.

4. PAYMENTS

4.1 Payments of fees under 3.1 and 3.2 will be due prior to the commencement of the study.

4.2 For services under 3.3, the customer shall provide a $55,000 deposit to APS prior to the commencement of the study. At the completion of the study the customer shall pay any remaining fees above the deposit to APS or shall be refunded any excess deposit amount by APS.

Schedule 7

General Plan

This schedule establishes a meter maintenance and testing program for electric meters in order to ensure an acceptable degree of performance in the registration of the energy consumption of Arizona Public Service Company (Company) customers. Company will file an annual report with the Arizona Corporation Commission summarizing the results of the meter maintenance and testing program.

Specific Plan

1. Single-Phase Self Contained Meters - Non-Solid State Hybrids and Electro-Mechanical

   1.1 Meters shall be separated into groups having common physical attributes and the average performance of each group will be determined based on the weighted average of the meter's percentage registration at light load (LL) and at full load (FL) giving the full load registration a weight factor of four (4).

   1.2 Analysis of the test results for each group evaluated shall be done in accordance with the statistical formulas outlined in ANSI/ASQC Z1.9 – 1995 Formulas B-3, Tables A-1, A-2 and B-5. The minimum sample size shall be 100 meters when possible.

2. Single Phase Self Contained Meters – Solid State

   Company will monitor performance of these types of meters through the Company Metering and Billing systems.

3. Three Phase Self-Contained Meters - Non-Solid State Hybrids and Electro-Mechanical

   Company shall monitor installations with the following types of meters for accuracy and recalibrate as necessary according to the following schedule:

   3.1 Three-phase meters with surge-proof magnets and without demand registers or pulse initiators: 16 years.

   3.2 Three phase block-interval demand-register-equipped kWh meters with surge-proof magnets: 12 years.

   3.3 Three phase lagged-demand meters: 8 years.

4. Three Phase Self-Contained Meters – Solid State

   Company will monitor performance for these types of meters through the Company Metering and Billing systems.

5. Three Phase Transformer-Rated Meter Installations – Solid State Hybrids and Electro-Mechanical

   Company will conduct a periodic testing program whereby three phase transformer-rated meter installations along with their associated equipment shall be inspected and tested for accuracy according to the following schedule:

5.1 Installations with 500 to 1,000 kW load: 4 years.

5.2 Installations with 1001 kW to 2000 kW load: 2 years.

5.3 Installations over 2000 kW load: 1 year.

Schedule 8

Arizona Public Service Company (APS or Company) regularly encounters situations in which APS cannot obtain a complete and valid meter read. Situations that result in an estimated meter read include inclement weather, lack of access to a customer's meter, energy diversion, labor unavailability and equipment malfunction. Without a valid meter read, the customer's energy usage and/or demand must be estimated in order to render a bill for the missing read period. A bill based on estimated usage is often referred to as an "estimated bill."

APS uses situation specific methods to estimate electrical usage to ensure that the most accurate usage estimate is obtained. This Schedule describes the estimation methods and procedures used when an actual meter read cannot be obtained or when energy diversion and/or meter tampering has occurred. The estimating process is applicable to customers receiving Standard Offer service and to direct access customers receiving unbundled delivery service from the Company.

1. GENERAL

1.1 Estimating a read for energy (kWh) and/or demand (kW) is performed in accordance with the provisions of this Schedule or such supplemental or amendatory guidelines or regulations as may hereafter be established and as provided by law.

1.2 This Schedule shall be considered a part of all rate schedules.

1.3 Upon discovery of the need to estimate kWh or kW, Company will make reasonable attempt (s) to secure an accurate meter reading and to resolve no-access issues.

1.4 Company is not obligated to obtain, or attempt to obtain, a customer supplied meter read prior to sending an estimated bill. In circumstances where APS has agreed in writing to permit customer supplied meter reads in accordance with Arizona Corporation Commission (ACC or Commission) regulations and that customer fails to provide Company with the meter read, estimation is also allowed.

1.5 Estimates due to equipment malfunctions may exceed one month if the malfunction of Company owned or maintained equipment could not be reasonably discovered and/or corrected before the need for additional estimates, or if the equipment malfunction is with regard to customer-owned or maintained equipment.

1.6 This schedule is not intended to supersede the Commission's rules and regulations in effect at the time the Commission approved this Schedule 8 without a specific decision of the Commission.

2. BILL ESTIMATION

2.1 The causes that result in an estimated bill include but are not limited to:

2.1.1 Inclement weather where conditions prevent meter access or compromise APS employee safety as determined by Company.

2.1.2 Lack of access to the meter either due to conditions on the customer's premise or to road closures that prevent access to the customer's premise.

2.1.3 Equipment or meter failure or malfunction with no reliable information retained by the meter.

2.1.4 Labor unavailability due to circumstances such as unforeseen illness, natural disasters, or other extreme events.

2.1.5 Meter tampering or energy diversion resulting in a lack of accurate metered consumption information.

2.1.6 An electronic meter reading is obtained, but the data cannot be transferred to a billing computer.

2.1.7 Only a partial read for a meter (for example, the total kWh read is obtained from a time-of-use meter, but on-peak kWh and/or kW reads are unavailable). Company will use the read available, and estimate the missing read(s).

2.2 The following defines certain conditions under which a bill is not considered estimated:

2.2.1 A bill based on an actual kWh read, following an estimated bill. This is considered a "true-up" bill and has an explanation of "true-up" on the bill.

2.2.2 Rate changes in the middle of the billing cycle.

2.2.3 A meter failure or malfunction which does not prevent the meter from accurately recording customer usage or from being read.

2.2.4 The meter read is not available using electronic meter reading devices, but data is obtained from a visual meter reading.

2.2.5 Meter reading information is not available because the service is provided on an un-metered basis.

2.2.6 Unbundled service for direct access customers is provided on the basis of load profiles in accordance with ACC regulations rather than using interval data metering.

2.2.7 When Company determines a meter is misread, but the actual read on the meter at the time it was read can be determined, Company makes a manual correction to the incorrect read. This includes, but is not limited to, the following examples:

2.2.7.1 A shut-off read is obtained, and on the same day the monthly meter read is taken and is higher by 1 kWh. The monthly meter read is changed to the same read as the shut off read.

2.2.7.2 The serviceman enters a shut-off or turn-on read and then calls into the office to say he entered the read for the wrong address. The correct reads are entered for the appropriate addresses.

2.2.7.3 Accurate consumption information can be obtained from load research meters.

2.2.8 A bill is estimated, and then rebilled when an actual read is obtained for the same billing period. The first bill is considered an estimated bill and is coded as such. The subsequent bill is considered a corrected bill and is not coded as an estimate, but does contain "corrected bill" language.

3. BILL ESTIMATION METHODS

The following section describes the estimation methods used to estimate energy consumption and demand for most instances. Estimation techniques required where special circumstances exist, such as initial bills, are also described. In general, the estimation methodologies utilize historical data.

3.1 ENERGY ESTIMATION (kWh)

For energy estimation, the following hierarchy is used: 1) The estimate will be based on the customer-specific prior month's energy consumption unless that month was an initial bill. 2) If the prior month's customer-specific energy consumption is not available or was an initial bill, the estimate will be based on the customer-specific energy consumption for the same month in the prior year. 3) If the customer-specific prior month or same month last year energy consumption is unavailable but adequate seasonal customer history exists, energy consumption will be estimated based on daily usage during six months of the same season. 4) If customer-specific energy consumption is not available, the estimate will be based on the prior month's energy consumption at that premise unless that month was an initial bill. 5) If prior month's premise energy consumption is not available or was an initial bill, the premise energy consumption for the same month in the prior year will be used to estimate consumption. 6) If premise-specific prior month or same month last year is unavailable but adequate seasonal premise history exists, energy consumption will be estimated based on daily usage during six months of the same season. 7) When adequate customer or premise history is not available, the estimate is based on the customer class average usage found in Section 3.3.1.

For customers served under time-of-use schedules, the hierarchy listed above will be utilized to develop the estimated on-peak and off-peak energy consumption.

For customers served under rate schedules SC-S, EPR-2, EPR-5, and EPR-6 the hierarchy listed above will be used to estimate the energy consumed by the Customer. Section 3.1.3 below shall be used to estimate any excess energy purchased by the Utility. For customers served under rate schedules E-56, CPP-RES and CPP-GS, the energy estimation will be addressed on a case-by-case basis.

For bill estimation purposes, the Summer Season is defined as May through October and the Winter Season is defined as November through April.

The energy estimation methods are described in detail below.

Previous Month Method

Estimated energy usage is calculated as follows:

1. Determine the number of days for the previous month's billing period.

2. Determine the kWh for the previous month's billing period.

3. Divide the previous month kWh by the previous month number of days to determine previous month per day usage.

4. Multiply the previous month per day usage by the number of days in the missing read billing period to yield the kWh for the missing read billing period.

Same Month Prior Year Method

Estimated energy is calculated as follows:

1. Determine the number of days for the same month of the previous year's billing period.

2. Determine the kWh for the same month of the previous year's billing period.

3. Divide the same month prior year's kWh by the same month prior year's number of days to get same month prior year per day usage.

4. Multiply the same month prior year per day usage by the number of days in the missing read billing period to yield the kWh for the missing read billing period.

Seasonal Average Method

Estimated energy is calculated as follows:

Where there is sufficient seasonal history (the number of days billed in the season is between 165 and 195 days), energy is estimated by calculating the average use per day for the same season as the billing period with the missing read. The resulting per day usage is multiplied by the number of days in the missing-read billing period to yield the usage estimate for the billing period. Seasonal average is calculated as follows:

1. Determine the total number of days from each of the previous six same-season months to yield seasonal total days.

2. Add the kWh from each of the previous six same-season months to yield seasonal total kWh.

3. Divide seasonal total kWh by seasonal total days to yield the seasonal per day usage.

4. Multiply the seasonal per day usage by the number of days in the missing read billing period to yield the kWh for the missing read billing period.

Class Average Method

Estimated energy usage is calculated as follows:

Where neither customer nor premise history is available, energy is estimated by calculating the average use per day for customer served under the same rate schedule. The resulting per day usage is multiplied by the number of days in the missing-read billing period to yield the usage estimate for the billing period.

3.1.1 TIME-OF-USE AND SEASONAL ESTIMATION (kWh):

If the rate for the estimated billing period is a time-of-use rate and sufficient time-of-use history does not exist for a customer or premise, on-peak energy usage is allocated as follows:

	Super Summer (Jun, Jul, Aug) ET-SP Only	Summer (May through October)	Winter (November through April)
Residential			
ET-1	-	40%	30%
ET-2	-	25%	16%
ET-SP			
Super Peak	12%	-	-
On-Peak (12-3, 6-7)	13%	-	-
On-Peak (12-7)	-	25%	19%
ECT-1R	-	40%	30%
ECT-2	-	23%	16%
Non-Residential			
All	-	32%	31%

NOTE: The percentages specified above will also apply for seasonal estimation of Customer-owned on-site distributed generators to include both the energy consumed by the Customer and any excess energy purchased by the utility.

Seasonal on-peak energy percentages listed above will be modified through general rate case or tariff filings or within three months whenever annual Load Research studies indicate that changes in these data are greater then 5%.

3.1.2 ENERGY ESTIMATION FOR CUSTOMER-OWNED ON-SITE DISTRIBUTED GENERATORS

For energy estimation for Customer-owned on-site distributed generators, the following hierarchy is used: 1) The estimate will be based on each generators previous month's energy output unless that month was an initial bill. 2) If the prior month's generator-specific energy output is not available or was an initial bill, the estimate will be based on the generator-specific energy output for the same month in the prior year. 3) If the generator-specific prior month or same month last year energy output is unavailable but adequate seasonal history exists for a similar type of generator, energy output will be estimated based on the similar generator's output during six months of the same season 4) If similar generator output is not available, the estimate will be based on the prior month's generation output at that premise unless that month was an initial bill. 5) If prior month's premise generator output is not available or was an initial bill, the premise generator output for the same month in the prior year will be used to

estimate generator output. 6) If premise-specific prior month or same month last year generator output is unavailable but adequate seasonal premise generation output history exists, energy output will be estimated based on daily generation output during six months of the same season. 7) When adequate Customer or similar generator output history is not available, the generator estimate is based on a 50% availability factor for the month (20% for PV systems).

For customers served under time-of-use schedules, the hierarchy listed above will be utilized to develop the estimated on-peak and off-peak energy consumption.

3.1.3 EXCESS POWER (ENERGY) ESTIMATION FOR CUSTOMERS WITH CUSTOMER-OWNED ON-SITE DISTRIBUTED GENERATORS

This section estimates the amount of Customer-owned on-site distributed generation energy provided to the APS distribution system ("Excess Power"). For Excess Power estimation for Customer-owned on-site distributed generators, the following hierarchy is used: 1) The estimate will be based on the previous month's Excess Power kWh level unless that month was an initial bill. 2) If the prior month's Excess Power kWh level is not available or was an initial bill, the estimate will be based on the Excess Power kWh level for the same month in the prior year. 3) If the Excess Power kWh level for the prior month or same month last year is unavailable but adequate seasonal Excess Power history exists, the Excess Power kWh level will be estimated based on the daily Excess Power kWh level during six months of the same season. 4) If the seasonal daily Excess Power kWh level is not available, the Customer's estimate will be based on the prior month's Excess Power kWh level at that premise unless that month was an initial bill. 5) If prior month's premise Excess Power kWh level is not available or was an initial bill, the premise Excess Power kWh level for the same month in the prior year will be used to estimate the Excess Power kWh level. 6) If premise-specific prior month or same month last year Excess Power kWh level data is unavailable but adequate seasonal premise Excess Power kWh level history exists, the Excess Power kWh level will be estimated based on the daily Excess Power kWh level during six months of the same season. . 7) When adequate Customer or similar Excess Power kWh level history is not available, the Excess Power kWh level estimate is based on the following formula:

a. Residential PV Systems: (1,630.8 x the nameplate continuous output power rating of the generating facility)/12 x .10
b. All other generating systems will be addressed on a case-by-case basis

For customers served under time-of-use schedules, the hierarchy listed above will be utilized to develop the estimated on-peak and off-peak Excess Power kWh levels.

3.2 DEMAND ESTIMATION

For those accounts where the missing read period is billed on a demand rate and the missing read billing period is not for an initial bill, demand is estimated using the following hierarchy:

3.2.1 If it is the same customer, use the prior month's demand unless that demand was estimated or is for an initial bill.

3.2.2 If it is the same customer, but the prior month's customer-specific demand is not available or was estimated or was an initial bill, use the customer-specific demand read from the same billing month a year ago, unless that demand was estimated or is for an initial bill.

3.2.3 If the bill for the same month of the prior year was not for the same customer, or was estimated or for an initial bill, use the premise demand read for the prior month, unless that demand was estimated or is for an initial bill.

3.2.4 If the prior month's premise demand was estimated or was an initial bill, use the premise demand read from the same billing month of the prior year, unless that demand was estimated or was for an initial bill.

3.2.5 For purposes of this Section 3.2., a demand read is considered "estimated" if the demand was not reset the prior month (or any time thereafter) and the demand read is not greater than the prior month's demand read which was not reset.

3.2.6 If none of the above is applicable, apply the rate schedule load factor percentage to the appropriate kWh. The rate schedule load factor percentages are:

Residential:	Load Factor %
-	-
ET-SP Super-Peak	43%
ET-SP On-Peak	38%
ECT-1R	42%
ECT-2	39%
Non-residential:	
All	50%

Load factors listed above will be modified through general rate case or tariff filings or within three months whenever annual Load Research studies indicate that changes in these data are greater than 5%.

3.2.7 From time to time, meter reader may be unable to reset demand readings. When this occurs the readings are noted as "Demand Not Reset."

3.2.7.1 In the month when the "Demand Not Reset" is noted, the kWh and kW are not estimates and are used for billing purposes.

3.2.7.2 In the following month, if the meter reader is able to reset the demand, the "Demand Not Reset" notation is removed.

1) If the kW reading is less than the reading for the previous month, the demand is used for billing purposes and is not an estimated demand.

2) If the demand reading is greater than the previous month when the "Demand Not Reset" was noted, the read demand is used.

3) If the demand reading is equal to the demand reading when the "Demand Not Reset" was noted, demand will be estimated using the procedures described in previous sections of this schedule.

3.2.8 DEMAND ESTIMATION FOR CUSTOMER-OWNED DISTRIBUTED GENERATORS

For those accounts where the missing read period is billed on a demand rate and the missing read billing period is not for an initial bill, demand is estimated using the following hierarchy:

3.2.8.1 If it is the same customer, use the prior month's demand from the Customer-owned generator unless that demand was estimated or is for an initial bill.

3.2.8.2 If it is the same customer, but the prior month's customer-specific demand from the generator is not available or was estimated or was an initial bill, use the customer-specific demand on the generator from the same billing month a year ago, unless that demand was estimated or is for an initial bill.

3.2.8.3 If the demand on the generator for the same month of the prior year was not for the same customer, or was estimated or for an initial bill, use the premise generator demand read for the prior month, unless that demand was estimated or is for an initial bill.

3.2.8.4 If the prior month's premise demand from the generator was estimated or was an initial bill, use the premise demand from the generator from the same billing month of the prior year.

3.2.8.5 For purposes of this Section 3.2., a demand read on the generator is considered "estimated" if the demand was not reset the prior month (or any time thereafter) and the demand read on the generator is not greater than the prior month's demand read which was not reset.

3.2.8.6 If none of the above is applicable, apply the rate schedule load factor percentage to the appropriate kWh. The rate schedule load factor percentages are:

Residential:	Load Factor %
ET-SP Super Peak	43%
ET-SP On-Peak	38%
ECT-1R	42%
ECT-2	39%
Non-residential:	
All	50%

Load factors listed above will be modified through general rate case or tariff filings or within three months whenever annual Load Research studies indicate that changes in these data are greater than 5%.

3.2.8.7 From time to time, meter reader may be unable to reset demand readings. When this occurs the readings are noted as "Demand Not Reset."

3.2.8.7.1 In the month when the "Demand Not Reset" is noted, the kWh and kW are not estimates and are used for billing purposes.

3.2.8.7.2 In the following month, if the meter reader is able to reset the demand on the generator, the "Demand Not Reset" notation is removed.

1) If the kW reading is less than the reading for the previous month, the demand on the generator is used for billing purposes and is not an estimated demand.

2) If the demand reading on the generator is greater than the previous month when the "Demand Not Reset" was noted, the read demand is used.

3) If the demand reading is equal to the demand reading when the "Demand Not Reset" was noted, demand will be estimated using the procedures described in previous sections of this schedule.

3.3 INITIAL BILL

An initial bill is the first bill a customer receives for a premise. Examples of an initial bill include a new meter set where no service has previously been provided, or a previously occupied premise that is now in the new connecting customer's name.

If the billing period for an initial bill is fewer than 11 days and no read was obtained, the customer is billed only a daily basic service charge, and any energy used during this period is included in the following month's billing period usage. If the billing period is 11 or more days, the bill is estimated as follows:

3.3.1 ENERGY USAGE (kWh):

If there is no usage history for the premise, a "minimum usage" estimate is multiplied by the number of days in the missing read billing period. The difference in energy used during this period and the "minimum usage" estimate is included in the following month's billing period usage. The "minimum usage" estimates for total kWh are:

Residential:	
E-12	25 kWh per day
ET-1 and ET-2	47 kWh per day
ET-SP	47 kWh per day
ECT-1R and ECT-2	75 kWh per day

Non-residential:

Under 20 kW	45 kWh per day
Over 20 kW	1,156 kWh per day

NOTE: The minimum usage estimates specified above also apply to energy consumed by the Customer under rate schedules EPR-2 and EPR-5. Excess energy purchased by the utility will be estimated at zero for the initial bill.

Initial bill minimum energy usage estimates for total kWh listed above will be modified through general rate case or tariff filings or within three months whenever annual Load Research studies indicate that changes in these data are greater then 5%.

If there is usage history for the premise, energy will be estimated using the applicable method in Section 3.1. If there is no on-peak usage history for the premise, the allocations found in Section 3.1.1 will be utilized.

3.3.2 DEMAND (kW):
For those accounts where the missing read period is billed on a demand rate, demand is estimated as follows:

For initial bills fewer than 11 days, no demand charge is billed.

For initial bills 11 or more days, the kW is estimated using the same hierarchy as indicated in Section 3.2.

3.4 ADVANCED METER INFRASTRUCTURE (AMI) METERS

When a missing read occurs on an account with an AMI meter, an initial attempt to estimate will be performed using partial month data as available. AMI meter data is normally collected on a daily basis, and therefore would be used to compute an estimate for the billing month, even if some of these daily reads are missing.

3.4.1 For initial and normal bills:

If the latest AMI meter data is available with a meter reading of 11 or more days since the last read date for the previous billing month:

1) Review the daily AMI incremental reads to determine the total energy consumption, on-peak percentage and demand for the billing month. Use reads from the latest AMI data to determine a per-day usage value and multiply by the number of days in the current billing period to yield the estimates for total and on-peak usage.

2) If the AMI meter data is unavailable use the estimation methods for non-AMI meters.

3.4.2 For initial and normal bills of 10 or less days, use the estimation methods described in Section 3.3.

3.5 DEAD OR FAILING METER

For accounts where it is determined the meter is dead or failing, no adjustment to the bill will be made until the new meter is in place at least 11 days. Then the usage for the previous month(s) is to be determined by taking the lower of the per day usage calculated from the new meter, less 3% (plus 3% for estimating customer-owned on-site generation bought by Utility), or the Same Month Prior Year Method described in Section 3.1. Charges for underbillings of dead or failing meters will be limited to three months for residential accounts and six months for non-residential accounts, in accordance with Schedule 1 Section 4.3. In instances where Company believes the customer's usage patterns were different during the dead or failing meter period than those being used to estimate, Company may adjust its estimate downward from either method.

3.6 ENERGY DIVERSION OR METER TAMPERING

In instances where energy diversion or meter tampering has occurred, meter reads from the meter will not accurately reflect all of the energy usage. Energy consumption for the period during which the diversion or meter tampering occurred shall be estimated by calculating a per day usage based on the best available information. This may include 1) metered data obtained from an auxiliary meter installed during the diversion investigation; 2) meter information obtained from the customer's meter after the diversion or meter tampering was discovered by Company and stopped; and 3) consumption history for the customer or site prior to when the diversion or meter tampering began.

In some instances, the estimated consumption based on per day usage may be less than what the meter actually registered during the time period. In those cases, the actual usage will be used in the calculation of the total energy diversion or meter tampering back bill.

3.7 NON-CUSTOMER INFORMATION SYSTEM ESTIMATES

In some instances, an account is coded to not be automatically estimated by Company's Customer Information System (CIS). This occurs when, due to special circumstances of the account (such as: served at substation voltage, receives a power allowance from a federal agency, partial requirements/self-generation, etc.), manual intervention in the billing process is required. For those accounts which are coded to not be automatically estimated by the CIS, additional attempts may be made to obtain meter readings which will be used for billing. If reads are not obtained, then energy and demand will be estimated, using the applicable methods described in this Schedule.

3.8 REBILLS OF PREVIOUS ESTIMATES

In instances where the reads from the previous month are estimated and a subsequent actual read is obtained, the following "true-up" is performed.

3.8.1 ENERGY USAGE

If the actual read following an estimated read is either lower than the estimated read, or, in Company's opinion, considerably higher than the previously estimated read(s), then per day usage is calculated using the difference in kWh between the last actual read and the current month actual read. The per day

usage is multiplied by the number of days in each estimated month and each affected month is rebilled using the new per day usage kWh.

3.8.2 DEMAND

If the actual demand read obtained after an estimate is lower than the estimated demand read, the previous month(s) estimated demand read(s) are lowered to the subsequent actual demand read.

The estimates used in this Section 3.8 take precedence over the estimating methods described elsewhere in this Service Schedule.

Schedule 9

SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE INDUSTRIAL DEVELOPMENT PLAN

This Schedule sets forth the conditions under which the company may offer incentives to potential new commercial or industrial customers or to adding new load. The purpose of this Schedule is to reduce average system costs by increasing sales beyond otherwise obtainable levels at prices that, though lower than standard rates, will recover all variable costs and contribute to fixed costs.

1. Availability

   1.1 To new loads increased existing loads that meet the eligibility criteria.
   1.2 Limited to the lesser of 100 MW of new and additional load or 50 new customers.

2. Eligibility Criteria

To determine if a customer is eligible for incentive the following criteria will be evaluated:

2.1 Consideration of Alternative Locations- Incentives are available only to customers who have not located or expanded in the Company's service area prior to the Commission's review of the application and who would not locate or expand in the Company's service area in the absence of the incentive. Customer must provide the Company with evidence of consideration of locations outside of the Company's service area. This evidence must consist of written documentation, including but not limited to detailed quantitative analyses of location factors for alternative sites performed by the customer and/or consultants. The Company will use this information to determine whether the customer would reasonably locate elsewhere in the absence of the incentive and, accordingly, meets this eligibility criterion.

2.2 Effects on Competitors- Incentives are available only when other customers in the same line of business and market are not adversely impacted by the discounted rates. The customer must provide a detailed description of goods and services the customer produces, the technology employed, and the market(s) the customer serves. Based on this information and knowledge of its customer base, the Company must reasonably verify that this criterion is satisfied.

2.3 Sizes of the Load- Eligible loads are new customers of 1,000 kW or current customers adding at least 500 kW. The customer's loads include power purchased from APS and power generated by the customer using congeneration or small power production methods.

2.4 Annual Load Factor- 55% or greater, unless the customer meets the off-peak, seasonal, or interruptible criteria.

2.5 Off-Peak Operation- If daily off-peak kWh (based on all remaining hours excluding 11:00 am.-9:00 pm Monday through Friday) is greater than 50% of total kWh, the load factor criterion may be waived.

2.6 Seasonality- Loads that do not operate in the summer months of June through September will be given special consideration in the evaluation of the suitable incentive.

2.7 Interruptibility- If the new load or added load is interruptible and the customer's peak load is at least 3,000 kW, the load factor criterion may be waived.

2.8 Permanency-The Company reserves the right to waive any eligibility criteria other than 2.1 or 2.1 to any potential load that will leave the Company's service territory by xxxxxxx

2.9 Economic Feasibility- The load must be economic, based on the Company's extension policy using standard rates.

2.10 External Economic Benefits- To be Eligible for the Plan, a potential load must bring a significant number of jobs and/or ancillary business into Arizona. In conjunction with this criterion, capital investment by the customer mat also be considered.

2.11 Significance of Electric Bill- The Company will give particular attention to customers whose electric bills exceed 5% of their operating expenses.

2.12 Other Considerations- The customer must furnish the Company with all requested information so that its eligibility can be evaluated and so that the Company can complete a Customer Characteristics Report. Any customer-provided information that the Company furnishes to the Commission Staff on a confidential basis, will be returned to the Company within 60 days of the Company's filings of the application.

2.13 Energy Efficiency- The customer will be assisted by APS and Commission Staff in considering and employing state of the art, cost effective energy conservation measures at its facility. These measures may include efficiency motors and motor control systems, and other general measures such as efficient lighting, space heating and cooling, and insulation.

2.14 Absence of Conflicts-of Interest - The Commission believes that in Lieu of requiring APS to submit information on the customer's officer and their relationship with APS and its affiliates to limit conflicts of interest, APS will be required to submit an affidavit on this subject. The affidavit should state that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries or affiliates has or had any interest, direct or indirect, with any entity which has provided substantial services, including real estate broker serives, to such customer in connection with its proposed Schedule 9 Agreement with APS. Further, the affidavit should state that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries or affiliates has or had any direct or indirect interest in any property owned in whole or part by the customer.

If the affidavit provided by APS is inaccurate, the Commission shall impute as revenue in APS' rate cases the difference between the discounted rate and the tariffed rate which would otherwise apply to the customer for the period during which the discount was effect.

3. Rate Provisions

3.1 The Qualifying Customer Remains on the Otherwise Applicable Rate Schedule- The customer satisfying the eligibility and customer criteria may receive a discount, which may vary over the term of the contract, from his otherwise applicable base bill (excluding taxes and adjustments), but in no case will the discounted energy charges be below the Company's marginal cost. For current customers adding load, the discount will apply only to the added load.
Example: A qualified customer may receive a discount of 20% from its base bill in years one and two, 15% in years three and four and no discount in year five.

3.2 Time Limitation- The rate benefits will be limited to a specific period of five years or less.

3.3 Minimum Bill- Customer will receive no discount from the minimum bill as computed under the otherwise applicable rate.

3.4 Applicable Percent Discount and Period of Application- The specific discount and the period over which the discount is applied shall be determined after full evaluation by the Company. The specific discount will not result in energy charges below the Company's marginal cost.

4. Contracts

A contract will be signed with each qualifying customer to guarantee adherence to the customer criteria, specifying the incentives, and specifying other pertinent terms where different from Company's Standard Terms and Conditions, Service Schedule 1. Unless otherwise acted upon by the Commission, each contract filed with the Commission shall be deemed approved 30 days after filing.

Each contract must be accompanied by a Customer Characteristic Report. The following information must be included in the Customer Characteristics Report:

4.1 General Information

- 4.1.1 Customer name
- 4.1.2 Customer contact—name and address
- 4.1.3 Dates of customer application and Company decision
- 4.1.4 New or existing customer
- 4.1.5 Proposed effective date of contract

4.2 Location Decision

- 4.2.1 Customer name
- 4.2.2 Description of other locations considered
- 4.2.3 Other locations of customer's operations
- 4.2.4 An affidavit from customer demonstrating that the customer would not locate or expand in Arizona absent the discounts
- 4.2.5 Within ninety (90) days of approval of any contract under this Schedule, the customer must supply written documentation and analyses substantiating the affidavit provided under 4.2.4
- 4.2.6 If the requirements of 4.2.5 are not met within ninety (90) days of approval of the contract, the contract shall be void.
- 4.2.7 Proportion of customer's production and distribution expenses accounted for by electricity, by natural gas and by other energy sources (specify)

4.3 Effects on Competitors

- 4.3.1 Nature of business—description and North American Industry Classification System (NAICS) code
- 4.3.2 Customer location
- 4.3.3 Number of other customers in same business
- 4.3.4 Market area served by customer
- 4.3.5 Description of effects on other customers

4.4 Load Characteristics

- 4.4.1 Size of load
- 4.4.2 Annual load factor
- 4.4.3 Off-peak operation
- 4.4.4 Description of daily load shape
- 4.4.5 Seasonality
- 4.4.6 Interruptibility
- 4.4.7 Permanency of load

4.5 Energy Service Mix
- 4.5.1 Use of natural gas and other energy sources
- 4.5.2 Description of energy efficiency measures—building design, processing and other
- 4.5.3 Feasibility of cogeneration

4.6 Rates
- 4.6.1 Applicable rate schedule
- 4.6.2 Years discount in effect
- 4.6.3 Percentage discount by year
- 4.6.4 Estimated annual revenues
- 4.6.5 Estimated annual incremental electricity production costs

4.7 Special Contract Provisions
- 4.7.1 List of special provisions
- 4.7.2 Reasons for special provisions

Schedule 10

The following terms and conditions and any changes authorized by law will apply to Arizona Public Service Company (Company), Energy Service Providers (ESPs), and their agents that participate in Direct Access under the Arizona Corporation Commission's (ACC) rules for retail electric competition (A.A.C. R14-2-1601, et seq., referred to herein as the "Rules"). "Direct Access customer" refers to any Company retail customer electing to procure its electricity and any other ACC authorized Competitive Services directly from ESPs as defined in the Rules.

Customer Selections

All Company retail customers shall obtain service under one of two options:

1. Standard Offer Service. With this election, retail customers will receive all services from Company, including metering, meter reading, billing, collection and other consumer information services, at regulated rates authorized by the ACC. Any customer who is eligible for Direct Access who does not elect to procure Competitive Services shall remain on Standard Offer Service. Direct Access customers may also choose to return to Standard Offer Service after having elected Direct Access.

2. Competitive Services (Direct Access). This service election allows customers who are eligible for Direct Access to purchase electric generation and other Competitive services from an ACC certificated ESP. Direct Access customers with single premise demands greater than 20 kW or usage of 100,000 kWh annually will be required to have Interval Metering, as specified in Section 3.6.1. Pursuant to the Rules, and any restrictions herein, the ESP serving these customers will have options available for choosing to offer Meter Services, Meter Reading Services and/or Billing Services on their own behalf (or through a qualified third party), or to have Company provide those services when permitted as specified herein.

1. General Terms

1.1 Definitions. The definitions of principal terms used in this Schedule shall have the same meaning as ascribed to them in the Rules, unless otherwise expressly stated in this Schedule.

1.1.1 Customer - Unless otherwise stated, all references to Customer in this agreement refer to Company customers who are eligible for and have elected Direct Access.

1.1.2 Service Account - Unless otherwise stated, all references to "Service Account" in this agreement shall refer to an installed service, identified by a Universal Node Identifier (UNI).

1.1.3 Local Arizona Time – All time references in this Schedule are in Local Arizona Time, which is Mountain Standard Time (MST).

2. General Obligations of Company

2.1 Non-Discrimination

2.1.1 Company shall discharge its responsibilities under the Rules in a non-discriminatory manner as to providers of all Competitive Services. Unless otherwise authorized by the ACC, the Federal Energy Regulatory Commission ("FERC") or applicable affiliate transactions rules, Company shall not:

2.1.1.1 Represent that its affiliates or customers of its affiliates will receive any different treatment with regard to the provision of Company services than other, unaffiliated services providers as a result of affiliation with Company; or

2.1.1.2 Provide its affiliates, or customers of its affiliates, any preference based on the affiliation including but not limited to terms and conditions of service, information, pricing or timing over non-affiliated suppliers or their customers in the provision of Company services.

2.2 Transmission and Distribution Service

Company will offer transmission and distribution services under applicable tariffs, schedules and contracts for delivery of electric generation to Direct Access customers under the provisions of State law, the terms of the ACC's Rules and Regulations, this Schedule, the ESP Service Acquisition Agreement, applicable tariffs and applicable FERC rules.

3. General Obligations of ESPs

3.1 Timeliness, Due Diligence and Security Requirements

3.1.1 ESPs shall exercise due diligence in meeting their obligations and deadlines under the Rules to facilitate customer choice. ESPs shall make all payments owed to Company in a timely manner.

3.1.2 ESPs shall adhere to all credit, deposit and security requirements specified in the ESP Service Acquisition Agreement and Company tariffs and schedules.

3.2 Arrangements with ESP Customers

ESPs shall be solely responsible for having appropriate contractual or other arrangements with their customers necessary to implement Direct Access. Company shall not be responsible for monitoring, reviewing or enforcing such contracts or arrangements.

3.3 Responsibility for Electric Purchases

ESPs will be responsible for the purchase of their Direct Access customers' electric generation needs and the delivery of such purchases to designated receipt points as set forth on schedules given to the Scheduling Coordinators ("SCs").

3.4 Company Not Liable for ESP Services

To the extent the customer elects to procure services from an ESP, Company has no obligations to the customer with respect to the services provided by the ESP.

3.5 Load Aggregation for Procuring Electric Generation/Split Loads

3.5.1 ESPs may aggregate individually-metered electric loads for procuring competitive electric generation only. Load aggregation shall not be used to compute Company charges or for tariff applicability.

3.5.2 Customers requesting Direct Access Services may not partition the electric loads of a Service Account among electric service options or providers. The entire load of a Service Account must be provided by only one (1) ESP. This provision shall not restrict the use of separate parties for metering and billing services.

3.6 Interval Metering

3.6.1 "Interval Metering" refers to the purchase, installation and maintenance of electricity metering equipment capable of measuring and recording minimum data requirements, including hourly interval data required for Direct Access settlement processes and distribution billing. Interval Metering is required for all customers that elect Direct Access and reach a single site maximum demand in excess of 20 kW one or more times or annual usage of 100,000 kWh or more. Interval Metering is provided by the ESP, at no cost to Company. Interval Metering is optional for those customers with single site maximum demands that are 20 kW or less or annual usage of less than 100,000 kWh.

3.6.2. Company shall determine if Customer meets the requirements for Interval Metering based on historical data, or an estimated calculation of the demand and/or usage for new customers.

3.7 Meter Data Requirements

Minimum meter data requirements consist of data required to bill Company distribution tariffs and determine transmission settlement. Company shall have access to meter data necessary for regulatory purposes or rate-setting purposes pursuant to mutually agreed upon terms with the ESP for such data access.

3.8 Statistical Load Profiles

Company will offer statistical load profiles in place of Interval Metering, for qualifying Customers to estimate hourly consumption for settlement and scheduling purposes. Statistical load profiles will be applied as authorized by FERC.

3.9 Fees and Other Charges

Direct Access customers shall pay all applicable fees, surcharges, impositions, assessments and taxes on the sale of energy or the provisions of other services as authorized by law. The ESP and Company will each be respectively responsible for paying such fees to the taxing or regulatory agency to the extent it is their obligation to do so. Both the ESP and Company will be responsible for providing the authorized billing agent the information necessary to bill these charges to the customer.

3.10 Liability In Connection With ESP Services

3.10.1 "Damages" shall include all losses, harm, costs and detriment, both direct and indirect, and consequential, suffered by Customer or third parties.

3.10.2 Company shall not be liable for any damages caused by Company conduct in compliance with, or as permitted by, Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service, or as otherwise set forth in Company's Schedule #1.

3.10.3 Company shall not be liable for any damages caused to Customer by any ESP, including failure to comply with Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service.

3.10.4 Company shall not be liable for any damages caused by the ESP's failure to perform any commitment to Customer.

3.10.5 An ESP is not a Company agent for any purpose. Company shall not be liable for any damages resulting from acts, omissions, or representations made by an ESP in connection with soliciting customers for Direct Access or rendering Competitive Services.

3.10.6 Under no circumstances shall Company be liable to Customer, ESP (including any entity retained by it to provide competitive services to the customer) or third parties for lost revenues or profits, indirect or consequential damages or punitive or exemplary damages in connection with Direct Access Services. This provision shall not limit remedies otherwise available to customers under Company's schedules and tariffs and applicable laws and regulations.

4. Customer Inquiries and Data Accessibility

4.1 Customer Inquiries – For customers requesting information on Direct Access, Company shall make available the following information:

4.1.1 Materials to consumers about competition and consumer choices.

4.1.2 A list of ESPs that have been issued a Certificate of Convenience and Necessity to offer Competitive Services within Company's service territory. Company will provide the list maintained by the ACC, but Company is under no obligation to assure the accuracy of this list. Reference to any particular ESP or group of ESPs on the list shall not be considered an endorsement or other form of recommendation by Company.

4.2 Access to Customer Usage Data. For Company customers on Standard Offer Service, Company shall provide customer specific usage data to ESP or to Customer, subject to the following provisions:

4.2.1 ESPs may request Customer usage data prior to submission of a Direct Access Service Request ("DASR") by obtaining and submitting to Company the Customer's written authorization on a Customer Information Service Request ("CISR") form. Company may charge for customer usage data at rates approved by the ACC.

4.2.2 Company will provide the most recent twelve (12) months of customer usage data or the amount of data available for that Customer if there is less than twelve (12) months of usage history.

4.3 Customer Inquires Concerning Billing Related Issues

4.3.1 Customer inquiries concerning Company charges or services shall be directed to Company.

4.3.2 Customer inquiries concerning ESP charges or services shall be directed to the ESP.

4.4 Customer Inquiries Related to Emergency Situations and Outages

4.4.1 Company shall be responsible for responding to all Standard Offer Service or, in the case of Direct Access customers, distribution service emergency system conditions, outages and safety situation inquiries related to Company's distribution system. Customers contacting an ESP with such inquiries are to be referred directly to Company for resolution. ESPs performing consolidated billing must show Company's emergency telephone number on their bills.

4.4.2 Company may shed or curtail customer load as provided by its ACC-approved tariffs and schedules, or by other ACC rules and regulations.

5. ESP Service Establishment

5.1 Before the ESP or its agents can offer Direct Access services in Company's distribution service territory they must meet the applicable provisions as listed:

5.1.1 All ESPs must obtain a Certificate of Convenience and Necessity from the ACC which authorizes the ESP to offer Competitive Services in Company's distribution service territory.

5.1.2 All ESPs must register to do business in the State of Arizona and obtain all other licenses and registrations needed as a legal predicate to the ESP's ability to offer Competitive Services in Company's distribution service territory.

5.1.3 Load Serving ESPs must satisfy creditworthiness requirements as specified in the ESP Service Acquisition Agreement if the ESP chooses the ESP Consolidated Billing option. If the ESP chooses Company UDC Consolidated Billing, they must enter into a Customized Billing Services Agreement.

5.1.4 Load Serving ESPs must enter into an ESP Service Acquisition Agreement with Company.

5.1.5 All ESPs must satisfy any applicable ACC electronic data exchange requirements including:

5.1.5.1 The ESP and/or its designated agents must complete to Company's satisfaction all necessary electronic interfaces between the ESP and Company to exchange DASRs and general communications.

5.1.5.2 The ESP or its agent must complete to Company's satisfaction all electronic interfaces between the ESP and Company to exchange meter reading and usage data. This includes communication to and from the Meter Reading Service Provider's (MRSP) server for sharing of meter reading and usage data.

5.1.5.3 The ESP must have the capability to electronically exchange data with Company. Alternative arrangements may be acceptable at Company's option.

5.1.5.4 The ESP and its agents must use Electronic Data Interchange (EDI) using Arizona Standard Formats to exchange billing and remittance data with Company when offering ESP Consolidated Billing or Company UDC Consolidated Billing. The ESP and its agents must use the Arizona Standard Format to exchange meter reading data with Company when providing meter reading services. Alternative arrangements may be allowed at Company's option.

5.1.6 For Company UDC Consolidated Billing or ESP Consolidated Billing options, compliance testing is required. Both parties must demonstrate the ability to perform data exchange functions required by the ACC and the ESP Service Acquisition Agreement. Any change of the billing agent will require a revalidation of the applicable compliance testing. Provided the ESP is acting diligently and in good faith, its failure to complete such compliance testing shall not affect its ability to offer electric generation to Direct Access customers. Dual Company/ESP Billing will be performed until the compliance testing is completed to Company's satisfaction.

5.1.7 Compliance testing will be required for a MRSP when providing meter reading services to ensure that meter data can be delivered successfully. Any change of the MRSP's system, or any change to the Arizona Standard 867 EDI format, will require a revalidation of the applicable compliance testing.

6. Direct Access Service Request (DASR)

6.1 A DASR is submitted pursuant to the terms and conditions of the Arizona DASR Handbook, the ESP Service Acquisition Agreement and this section, and shall also be used to define the Competitive Services that the ESP will provide the customer.

6.2 ESPs shall have a CC&N from the ACC; shall have entered into an ESP Service Acquisition Agreement with Company, if required, and shall have successfully completed data exchange compliance testing before submitting DASRs.

6.3 The customer's authorized ESP must submit a completed DASR to Company before Customer can be switched from Standard Offer Service or Competitive Service provided by another ESP. The DASR process described herein shall be used for customer Direct Access elections, updates, cancellations, customer-initiated returns to Company Standard Offer Service, or requests for physical disconnection of service and ESP- or customer-initiated termination of an ESP/customer service agreement.

6.4 A separate DASR must be submitted for each service delivery point. Each of the five (5) DASR operation types [Request (RQ), Termination of Service Agreement (TS), Physical Disconnect (PD), Cancel (CL) and Update/Change (UC)] has specific field requirements that must be fully completed before the DASR is submitted to Company. A DASR that does not contain the required field information or is otherwise incomplete may be rejected. In accordance with the provisions of the applicable Service Acquisition Agreement, Company may deny the ESP or customer request for service if the information provided in the DASR is false, incomplete, or inaccurate in any material respect. ESPs filing DASRs are thereby representing that they have their customer's authorization for such transaction.

6.5 Company requires that DASRs be submitted electronically using Electronic Data Interchange (EDI) or Comma Separated Value (CSV) formats through the Company's web site (http://esp.apsc.com).

6.6 DASRs will be handled on a first-come, first-served basis. Each request shall be time and date stamped when received by Company.

6.7 Once the DASR is submitted, the following timeframes will apply:

6.7.1 Company will respond to RQ, TS, CL and UC DASRs within two (2) working days of the time and date stamp. Company will exercise best efforts (no later than five (5) working days) to provide the ESP with a DASR status notification informing them whether the DASR has been accepted, rejected or placed in a pending status awaiting further information. If accepted, the effective switch date will be determined in accordance with Sections 6.8, 6.9, and 6.12 and will be confirmed in the response to the ESP and the former ESP if applicable. If a DASR is rejected, Company shall provide the reasons for the rejection. If a DASR is held pending further information, it shall be rejected if the DASR is not completed with the required information within thirty (30) working days, or a mutually agreed upon date, following the status notification. Company will send written notification to the customer once the RQ DASR has been processed.

6.7.2 When a customer requests electric services to be disconnected, the ESP is responsible for submitting a PD DASR to Company on behalf of the customer, regardless of the Meter Service Provider (MSP).

6.7.2.1 When Company is acting as the MSP, Company shall perform the physical disconnect of the service. The PD DASR must be received by Company at least three (3) working days prior to the requested disconnect date. Company will acknowledge the PD DASR status within two (2) working days of the time and date stamp.

6.7.2.2 When Company is not acting as the MSP, the ESP is responsible for performing the physical disconnect. The ESP shall notify Company by DASR of the date of the physical disconnect. Disconnect reads must be posted to the server within three (3) working days following the disconnection.

6.8 DASRs that do not require a meter exchange must be received by Company at least fifteen (15) calendar days prior to the next scheduled meter read date. The actual meter read date would be the effective switch date. DASRs received less than fifteen (15) calendar days prior to the next scheduled meter read date will be scheduled for switch to Direct Access on the following month's read date.

6.9 DASRs that require a meter exchange will have an effective change date to Direct Access as of the meter exchange date. Notification of meter exchange dates shall be coordinated between the ESP, MSP and Company's Meter Activity Coordinator ("MAC").

6.10 If more than one (1) RQ DASR is received for a service delivery point within a Customer's billing cycle, only the first valid DASR received shall be processed in that period. All subsequent DASRs shall be rejected.

6.11 Upon acceptance of an RQ DASR, a maximum of twelve (12) months of customer usage data, or the available usage for that customer switching from Standard Offer, shall be provided to the ESP. If there is an existing ESP currently serving that customer, that ESP shall be responsible for submitting the customer usage data to the new ESP. In both cases, the customer usage data will be submitted to the appropriate ESP no later than five (5) working days before the scheduled switch date.

6.12 Customers returning to Company Standard Offer service must contact their ESP. The ESP shall be responsible for submitting the DASR on behalf of the customer.

6.13 ESPs requesting to return a Direct Access customer to Company Standard Offer service shall submit a TS DASR and shall be responsible for the continued provision of the customer's electric supply service, metering, and billing services until the effective change date.

6.14 Customers requesting to return to Company Standard Offer service are subject to the same timing requirements as used to establish Direct Access service. Direct Access customers returning to Company Standard Offer service may be subject to the RCDAC-1.

6.15 Company may assess a fee for processing DASRs. All fees are payable to Company within fifteen (15) calendar days after the invoice date. All unpaid fees received after this date will be assessed applicable late fees pursuant to Schedule 1. If an ESP fails to pay these fees within thirty (30) days after the due date, Company may suspend accepting DASRs from the ESP unless a deposit sufficient to cover the fees due is currently available or until such time as the fees are paid. If an ESP is late in paying fees, a deposit or an additional deposit may be required from the ESP.

6.16 A customer moving to new premises may retain or start Direct Access immediately. The customer must first contact Company to establish a Service Account. The customer will be provided the necessary information that will enable its ESP to submit a DASR. The same timing requirements apply as set forth in Section 6.8 and 6.9.

6.17 Billing and metering option changes are requested through a UC DASR and cannot be changed more than once per billing cycle.

6.18 Company shall not hold the ESP responsible for any customer unpaid billing charges prior to the customer's switch to Direct Access. Unpaid billing charges shall not delay the processing of DASRs

and shall remain the customer's responsibility to pay Company. Company's Schedule 1 applies in the event of customer non-payment, which includes the possible disconnection of distribution services. Company shall not accept any DASRs submitted for customers who have been terminated for nonpayment and have not yet been reinstated. Disconnection by Company of a delinquent customer shall not make Company liable to the ESP or third-parties for the customer's disconnection.

6.19 Company shall not accept DASRs that specify a switch date of more than sixty (60) calendar days from the date the DASR is submitted.

7. Billing Service Options and Obligations

7.1 Subject to availability, and pursuant to the terms in the ESP Service Acquisition Agreement, this Schedule 10, and applicable tariffs and the restrictions therein, ESPs may select among the following billing options:

7.1.1 COMPANY UDC CONSOLIDATED BILLING

7.1.2 ESP CONSOLIDATED BILLING

7.1.3 DUAL COMPANY/ESP BILLING

7.2 COMPANY UDC CONSOLIDATED BILLING

7.2.1 The customer's authorized ESP sends its bill-ready data to Company, and Company sends a consolidated bill containing both Company and ESP charges to the Customer.

7.2.2 Company Obligations:

7.2.2.1 Company shall bill the ESP charges and send the bill either by mail or electronic means to the customer. Company is not responsible for computing or determining the accuracy of the ESP charges. Company is not required to estimate ESP charges if the expected bill ready data is not received nor is Company required to delay Company billing. Billing rendered on behalf of the ESP by Company shall comply with A.A.C. R14-2-1612.

7.2.2.2 Company bills shall include in Customer's bill a detailed total of ESP charges and applicable taxes, assessments and billed fees, the ESP's name and telephone number, and other information provided by the ESP.

7.2.2.3 If Company processes Customer payments on behalf of the ESP, the ESP shall receive payment for its charges as specified in Section 7.7.

7.2.3 ESP Obligations

7.2.3.1 Once a billing election is in place as specified in the ESP Service Acquisition Agreement, the ESP may offer Company UDC Consolidated Billing services to Direct Access customers pursuant to the terms and conditions of the applicable ACC approved tariff.

7.2.3.2 The ESP shall submit the necessary billing information to facilitate billing services under this billing option by Service Account, according to Company's meter reading schedule, and pursuant to the applicable tariff. Timing of billing submittals is provided for in Section 7.2.4 below.

7.2.4 Timing Requirements

7.2.4.1 Bills under this option will be rendered once a month. Nothing contained in this Schedule shall limit Company's ability to render bills more frequently consistent with Company's existing practices. However, if Company renders bills more frequently than once a month, ESP charges need only to be calculated based on monthly billing periods.

7.2.4.2 Except as provided in Section 7.2.4.1, Company shall require that all ESP and Company charges be based on the same billing period data.

7.2.4.3 ESP charges for normal monthly customer billing and any adjustments for prior months' metering or billing errors must be received by Company in EDI "810" format no later than 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date. If billing charges have not been received from the ESP by this deadline, Company will render a bill for Company charges only. The ESP must wait until the next billing cycle, unless there is a mutual agreement for Company to send an interim bill. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. An interim bill issued pursuant to this Section may also include a message that Company charges were previously billed.

7.2.4.4 ESP charges for a Physical Disconnect Final Bill must be received by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If final billing charges have not been received from the ESP by this date, Company will render the customer's final bill for Company charges only, without the ESP's final charges. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. The ESP must send the final charges to Company. Company will produce and send a separate bill for the final billing charges.

7.2.5 Restrictions

Company UDC Consolidated Billing shall be an option for individual customer bills only, not an aggregated group of customers. Nothing in this Section precludes each individual customer in an aggregated group, however, from receiving the customer's individual bills under Company UDC Consolidated Billing.

7.3 ESP CONSOLIDATED BILLING

7.3.1 Company calculates and sends its bill-ready data to the ESP. The ESP in turn sends a consolidated bill to its customer. The ESP shall be obligated to provide the customer detailed Company charges to the extent that the ESP receives such detail from Company. The ESP is not responsible for the accuracy of Company charges.

7.3.2 Company Obligations:

7.3.2.1 Company shall calculate all its charges once per month based on existing Company billing cycles and provide these to the ESP to be included on the ESP consolidated bill or as otherwise specified. Company and the ESP may mutually agree to alternative options for the calculation of Company charges.

7.3.2.2 Company shall provide the ESP with sufficient detail of its charges, including any adjustments for prior months' metering and billing error, by EDI "810" format. Company charges that are not transmitted to the ESP by 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date need not be included in the ESP's

bill. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges unless there is a mutual agreement to have the ESP send an interim bill to the customer including Company charges. The ESP will include a message on the bill stating that Company charges are forthcoming.

7.3.2.3 For a Physical Disconnect Final Bill, Company will provide the ESP with Company's final bill charges by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges. The ESP shall include a message on the bill stating that Company charges are forthcoming. Company will send the final bill charges to the ESP, and the ESP will produce and deliver a separate bill for Company charges.

7.3.3 ESP Obligations:

7.3.3.1 Once an ESP Service Acquisition Agreement is entered into, including an appropriate billing election, and all other applicable prerequisites are met, the ESP may offer consolidated billing services to Direct Access customers they serve.

7.3.3.2 The ESP bill shall include any billing-related details of Company charges. Company charges may be printed with the ESP bill or electronically transmitted. Billing rendered on behalf of Company by the ESP shall comply with A.A.C. R14-2-1612.

7.3.3.3 Other than including the billing data provided by Company on the customer's bill, the ESP has no obligations regarding the accuracy of Company charges or for disputes related to these charges. Disputed charges shall be handled according to ACC procedures.

7.3.3.4 The ESP shall process customer payments and handle collection responsibilities. Under this billing option, the ESP must pay all charges due to Company and not disputed by the customer as specified in Section 7.7.2.1.

7.3.3.5 Subject to the limitations of this Section and with the written consent of the Customer, the ESP may offer customers customized billing cycles or payment plans which permit the Customer to pay the ESP for Company charges in different amounts than Company charges to the ESP for any given billing period. Such plans shall not, however, affect in any manner the obligation of the ESP to pay all Company charges in full. Should Customer select an optional payment plan, all Company charges must be billed in accordance with A.A.C. R14-2-210(G).

7.3.4 Timing Requirements

ESPs may render bills more or less frequently than once a month. However, Company shall continue to bill the ESP each billing cycle period for the amounts due by the customer for that billing month.

7.4 DUAL COMPANY/ESP BILLING

Company and the ESP each separately bill the customer directly for services provided by them. The billing method is the sole responsibility of Company and the ESP. Company and the ESP shall process only the customer payments relating to their respective charges.

7.5 Billing Information and Inserts

7.5.1 All customers, including Direct Access customers, shall receive mandated legal, safety and other notices equally in accordance with A.A.C. R14-2-204 (B). If the ESP is providing consolidated billing, Company shall make available one (1) copy of these notices to the ESP for distribution to customers or, at the ESP's request, in electronic format to the ESP for production and communication to electronically billed Customers. If Company is providing Consolidated billing services, Company shall continue to provide these notices.

7.5.2 Under Company UDC Consolidated Billing, ESP bill inserts may be included pursuant to the applicable Company tariff.

7.6 Billing Adjustments for Meter and Billing Error

7.6.1 Meter and Billing Error

7.6.1.1 The MSP (including the ESP or Company if providing such services) shall resolve any meter errors and must notify the ESP and Company, as applicable, so any billing adjustments can be made. All other affected parties, including the appropriate Scheduling Coordinator, shall be notified by the ESP.

7.6.1.2 A billing error is the incorrect billing of Customer's energy or demand. If the MSP, MRSP, ESP or Company becomes aware of a potential billing error, the party discovering the billing error shall contact the ESP and Company, as applicable, to investigate the error. If it is determined that there is in fact a billing error, the ESP and Company will make any necessary adjustments and notify all other affected parties in a timely manner.

7.6.1.3 Company UDC Consolidated Billing

7.6.1.3.1 Company shall be responsible for notifying Customer and adjusting the bill for its charges to the extent those charges were affected by the meter or billing error.

7.6.1.3.2 The ESP shall be responsible for any recalculation of the ESP charges. Following the receipt of the recalculated charges from the ESP, the charges or credits will be applied to Customer's next normal monthly bill, unless there is mutual agreement to have Company send an interim bill to the Customer including the ESP's charges.

7.6.1.4 ESP Consolidated Billing

7.6.1.4.1 The ESP shall be responsible for notifying the Customer and adjusting the bill for ESP charges to the extent those charges were affected by the meter or billing error. The Customer shall be solely responsible for obtaining refunds of ESP electric generation overcharges from its current and prior ESPs, as appropriate.

7.6.1.4.2 Company shall transmit its adjusted charges and any refunds to the ESP with Customer's next normal monthly bill. The ESP shall apply the charges to Customer's next normal monthly bill, unless there is a mutual agreement to have the ESP send an interim bill to Customer including Company charges.

7.6.1.5 Dual Company/ESP Billing

7.6.1.5.1 Company and the ESP shall be separately responsible for notifying Customer and adjusting its respective bill for their charges.

7.7 Payment and Collection Terms

7.7.1 Company UDC Consolidated Billing

7.7.1.1 Company shall remit payments to the ESP for the total ESP charges collected from Customer within three (3) working days after Customer's payment is received. Company is not required to pay amounts owed to the ESP for ESP charges billed but not received by Company.

7.7.1.2 Customer is obligated to pay Company for all undisputed Company and ESP charges consistent with existing tariffs and other contractual arrangements for service between the ESP and the customer.

7.7.1.3 The ESP is responsible for all collections related to the ESP services on the Customer's bill, including, but not limited to, security deposits and late charges unless otherwise agreed upon in the customized billing services agreement between ESP and Company.

7.7.1.4 Payment for any Company charges for Consolidated Billing is due in full from the ESP within fifteen (15) calendar days of the date Company charges are rendered to the ESP. Any payment not received within this time frame will be assessed applicable late charges pursuant to Schedule 1. If an ESP fails to pay these charges prior to the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2 ESP Consolidated Billing

7.7.2.1 Payment is due in full from the ESP within fifteen (15) calendar days after the date Company's charges are rendered to the ESP. The ESP shall pay all undisputed Company charges regardless of whether Customer has paid the ESP. All payments received after fifteen (15) calendar days will be assessed applicable late charges pursuant to Schedule 1. If an ESP fails to pay these charges prior to the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2.2 Company shall be responsible for any follow-up inquiries with the ESP if there is question concerning the payment amount.

7.7.2.3 Company has no payment obligations to the ESP for Customer payments under ESP Consolidated Billing services.

7.7.3 Dual Company/ESP Billing

Company and the ESP are separately responsible for collection of Customer payment for their respective charges.

7.8 Late or Partial Payments and Unpaid Bills

7.8.1 Company UDC Consolidated Billing

7.8.1.1 Company shall not be responsible for ESP's Customer collections, collecting the unpaid balance of ESP charges from Customers, sending notices informing Customers of unpaid

ESP balances, or taking any action to recover the unpaid amounts owed the ESP. The ESP shall assume any collection obligations and/or late charge assessments for late or unpaid balances related to ESP charges under this billing option.

7.8.1.2 All Customer payments shall be applied first to unpaid balances identified as Company charges until such balances are paid in full, then applied to ESP charges. A Customer may dispute charges as provided by A.A.C. R14-2-212, but a Customer will not otherwise have the right to direct partial payments between Company and the ESP.

7.8.1.3 ACC rules shall apply to late or non-payment of all Company customer charges. Undisputed Company delinquent balances owed on a customer account shall be considered late and subject to Company late payment procedures.

7.8.2 ESP Consolidated Billing

The ESP shall be responsible for collecting both unpaid ESP and Company charges, sending notices informing Customers of unpaid ESP and Company balances, and taking appropriate actions to recover the amounts owed. Company shall not assume any collection obligations under this billing option and ESP is liable to Company for all undisputed payments owed Company.

7.8.3 Dual Company/ESP Billing

Company and the ESP are responsible for collecting their respective unpaid balances, sending notices to Customers informing them of the unpaid balance, and taking appropriate actions to recover their respective unpaid balances. Customer disputes with ESP charges must be directed to the ESP and Customer disputes with Company charges must be directed to Company.

7.9 Service Disconnects and Reconnects

In accordance with ACC rules, Company has the right to disconnect electric service to the Customer for a variety of reasons, including, but not limited to, the non-payment of Company's final bills or any past due charges by Customer, or evidence of safety violations, energy theft, or fraud, by Customer. The following provides for service disconnects and reconnects.

7.9.1 Company shall notify Customer and Customer's ESP of Company's intent to disconnect electric service for the non-payment of Company charges prior to disconnecting electric service to the Customer. Company shall further notify the ESP at the time Customer has been disconnected. To the extent authorized by the ACC, a service charge shall be imposed on Customer if a field call is performed to disconnect electric service.

7.9.2 Company shall reconnect electric service for a fee when the criteria for reconnection have been met to Company's satisfaction. Company shall notify the ESP of a Customer's reconnection.

7.9.3 Company shall not disconnect electric service to Customer for the non-payment of ESP charges by Customer. In the event of non-payment of ESP charges by Customer, the ESP may submit a DASR requesting termination of the service agreement and request return to Company Standard Offer Service. Company will then advise the Customer that they will be placed on Company Standard Offer Service unless a DASR is received from another ESP on their behalf.

7.10 Involuntary Service Changes

7.10.1 A Customer may have its service of electricity, billing, or metering from an ESP changed to another provider, including Company, involuntarily in the following circumstances:

7.10.1.1 The ACC has decertified the ESP or the ESP otherwise receives an ACC order that prohibits the ESP from serving the customer.

7.10.1.2 The ESP, including its agents, has materially failed to meet its obligations under the terms of its ESP Service Acquisition Agreement with Company (including applicable tariffs and schedules) so as to constitute an Event of Default under the terms of the ESP Service Acquisition Agreement, and Company exercises its contractual right to terminate the ESP Service Acquisition Agreement.

7.10.1.3 The ESP has materially failed to meet its obligations under the terms of the ESP Service Acquisition Agreement (including applicable tariffs and schedules) so as to constitute an Event of Default and Company exercises a contractual right to change billing options.

7.10.1.4 The ESP ceases to perform by failing to provide schedules through a Scheduling Coordinator whenever such schedules are required, or the ESP fails to have a Service Acquisition Agreement in place with a Scheduling Coordinator.

7.10.1.5 The Customer fails to meet its Direct Access requirements and obligations under the ACC rules and Company tariffs and schedules.

7.10.2 Change of Service Election in Exigent Circumstances

In the event Company finds that an ESP or the Customer has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company elects to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3) and the failure constitutes an emergency (defined as posing a substantial threat to the reliability of the electric system or to public health and safety), or the failure relates to ESP's sale of unscheduled energy, Company may initiate a change in the Customer's service election, or terminate an ESP's ability to offer certain services under Direct Access. In such case, Company shall initiate the change or termination by preparing a DASR, but the change or termination may be made immediately notwithstanding the applicable DASR processing times set forth in this Schedule. Company shall provide such notice and opportunity to remedy the problem if there are reasonable circumstances prevailing. Additionally, Company shall notify the ACC of the circumstances that required the change or the termination and the resulting action taken by Company. The ESP and/or Customer shall have the right to seek an order from the ACC restoring the customer's service election and/or the ESP's ability to offer services. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to Customer other than as provided in Section 4.4.2.

7.10.3 Change in Service Election Absent Exigent Circumstances

7.10.3.1 In the event Company finds that an ESP has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company seeks to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3), and the failure does not constitute an emergency (as defined in Section 7.10.2) or involve an ESP's unauthorized energy use, Company shall notify the ESP and the ACC of such finding in writing stating the following:

7.10.3.1.1 The nature of the alleged failure;

7.10.3.1.2 The actions necessary to remedy the failure;

7.10.3.1.3 The name, address and telephone number of a contact person at the Company authorized to discuss resolution of the failure.

7.10.3.2 The ESP shall have thirty (30) calendar days from receipt of such notice to remedy the alleged failure or reach an agreement with Company regarding the alleged failure. If the failure is not remedied and no agreement is reached between Company and the ESP

following this thirty (30) day period, Company may initiate the DASR process set forth in this Schedule to accomplish its remedy and shall notify the customers of such remedy. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to the customer other than as provided in Section 4.4.2.

7.10.4 Termination of ESP Consolidated Billing

7.10.4.1 Company may terminate ESP Consolidated Billing under the following circumstances:

7.10.4.1.1 The Company shall notify affected Customers that ESP Consolidated Billing services will be terminated, and the Company may switch affected Customers to Dual Company/ESP billing as promptly as possible if any of the following occur:

7.10.4.1.1.1 Company finds that the information provided by the ESP in the ESP Service Acquisition Agreement is materially false, incomplete, or inaccurate.

7.10.4.1.1.2 The ESP attempts to avoid payment of Company charges.

7.10.4.1.1.3 The ESP files for bankruptcy.

7.10.4.1.1.4 The ESP fails to have an involuntary bankruptcy proceeding filed against the ESP dismissed within sixty (60) calendar days.

7.10.4.1.1.5 The ESP admits insolvency.

7.10.4.1.1.6 The ESP makes a general assignment for the benefit of creditors.

7.10.4.1.1.7 The ESP is unable to pay its debts as they mature.

7.10.4.1.1.8 The ESP has a trustee or receiver appointed over all, or a substantial portion, of its assets.

7.10.4.1.2 If the ESP fails to pay Company (or dispute payment pursuant to the procedures set forth in this Schedule) the full amount of all Company charges and fees by the applicable due date, Company shall notify the ESP of the past due amount within two (2) working days of the applicable past due date. If the ESP incurs late charges on more than two (2) occasions or fails to pay overdue amounts including late charges within five (5) working days of the receipt of notice by Company, Company may notify the ESP's customers and the ESP that ESP Consolidated

Billing services will be terminated, and that Customers shall be switched to Dual Billing.

7.10.4.1.3 If the ESP fails to comply within thirty (30) calendar days of the receipt of notice from Company of any additional credit, security or deposit requirements set forth in Sections 5.1.3 and 7.11, Company may notify the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.

7.10.4.2 Upon termination of ESP Consolidated Billing pursuant to Section 7.10.4, Company may deliver a separate bill for all Company charges which were not previously billed by the ESP.

7.10.4.3 Company may reinstate the ESP's eligibility to engage in ESP Consolidated Billing upon a reasonable showing by the ESP that the problems causing the revocation of ESP Consolidated Billing have been cured, including payment of any late charges, reestablishing credit requirements in compliance with Sections 5.1.4 and 7.11, and payment to Company of all costsassociated with changing ESP customers' billing elections to and from dual billing.

7.10.4.4 In the event Company terminates ESP Consolidated Billing, Company will return any security posted by the ESP pursuant to the ESP Service Acquisition Agreement.

7.10.5 Termination of Company UDC Consolidated Billing

7.10.5.1 Company may terminate Company UDC Consolidated Billing and revert to Dual Billing upon providing thirty (30) calendar days notice to an ESP if ESP fails to pay Company charges in connection with Company UDC Consolidated Billing or otherwise fails to comply with its obligations under Section 7.2.

7.10.5.2 Company may terminate Consolidated Billing upon providing thirty (30) days notice to an ESP if Company cancels or changes the tariff governing Company UDC Consolidated Billing.

7.10.6 Upon termination of ESP Direct Access services pursuant to Section 7.10, the provision of the affected service(s) shall be assumed by another eligible ESP from which the Customer elects to obtain the affected service(s). Absent an election by Customer, Company shall provide such services, until such time that Customer makes an election.

7.10.7 Company shall not use involuntary service changes in an anticompetitive or discriminatory manner.

7.11 ESP Security Deposits

7.11.1 Company may, at its discretion, require cash security deposits from any ESP that has on more than one occasion failed to pay Company charges or ACC-approved Direct Access charges within the established time frame, such as DASR fees, meter or billing error or service fees, and other fees applicable to an ESP through Schedule 10 and Company's other tariffs and schedules.

7.11.2 The amount of the security deposit required shall not exceed two and one-half times the estimated maximum monthly bill to the ESP for such charges, and a separate security deposit may be required for separate categories of ESP or Direct Access charges.

7.11.3 Security deposits required pursuant to Section 7.11 shall be in the form of a cash deposit accruing interest as specified in Section 2.7.4 of Company Schedule 1. Company shall issue the ESP a nonnegotiable receipt for the amount of the deposit.

7.11.4 Company may refuse to accept DASRs from, or provide other Company services to, an ESP that fails to comply within thirty (30) calendar days to a demand that the ESP establish a security deposit pursuant to Section 7.11

8. Meter Services

8.1 Under Direct Access, ESPs may offer certain metering services for Direct Access implementation, including meter ownership, MSP and MRSP services.

8.2 Company has the right to offer the following meter services:

8.2.1 Metering and Meter Reading for all Direct Access Customers.

8.2.1.1 If the ESP subcontracts with the UDC for Meter Services they must subcontract for both Metering and Meter Reading Services. The ESP shall remain responsible for all cost associated with Metering, Meter Installation, Meter Communications and other MSRP related cost. All such cost shall be authorized by the ACC.

8.2.2 Services as authorized by the ACC.

8.2.3 Company reserves the right to perform meter disconnects, regardless of meter ownership, in cases of potential safety hazards or non-payment for Company charges.

8.3 A Load Serving ESP may sub-contract Metering or Meter Reading Services to a certificated third party or the UDC. If the ESP sub-contracts any of the components of these services to a third party or UDC, the ESP shall, for the purposes of this Schedule, remain responsible for the services including communication equipment, meter reading equipment and associated maintenance necessary to obtain reads from specialized meters that may be required by a Direct Access Customers.

8.4 Load Serving ESPs providing Metering or Meter Reading Services to Direct Access customers either on their own or through a third party or UDC assume full responsibility for meeting the applicable meter and communication standards, as well as assuming responsibility for the safe installation and operation of the meter and any personal injuries and damage caused to customer or Company property by the meter or its installation. This liability will lie with the ESP regardless of whether the ESP or its subcontractors perform the work.

8.5 Meter Specifications

8.5.1 The Director of Utilities Division of the ACC has determined the following specifications and standards shall apply to competitive metering where applicable (see Performance Metering Specifications and Standards document):

8.5.2 Metering standards (American National Standards Institute):

ANSI C12.1	Code for Electricity Metering
ANSI C12.6	Marketing & Arrangement of Terminals for Phase Shifting Devices used in Metering
ANSI C12.7	Watt-hour Meter Socket

ANSI C12.10	Electromechanical Watt-hour Meters
ANSI C12.13	Electronic TOU Registers for Electricity Meters
ANSI C12.18	Type 2 Optical Port
ANSI C12.20	0.2% & 0.5% Accuracy Class Meters
ANSI C37.90	Surge Withstand Test ANSI 57.13 Instrument Transformers (All CTs & PTs)
ANSI Z1.4	Sampling Procedures and Tables for Inspection
ANSI Z1.9	Sampling Procedures and Tables for Inspection

8.5.3 EEI Electricity Metering Handbook

8.5.4 Electric Utilities Service Equipment Requirements Committee (EUSERC)

8.5.5 NEC & Local Requirements by jurisdictions

8.5.6 Company's Electric Service Requirements Manual (ESRM)

8.5.7 National Electrical Safety Code (NESC)

8.5.8 ESPs or their contractors providing competitive metering services shall also comply with such other specifications or standards determined to be applicable or appropriate by the ACC's Director of Utilities Division.

8.6 Meter Conformity

8.6.1 All Direct Access meters shall have a visual kWh display and must have a physical interface to enable on-site interrogation of all stored meter data. All meters installed must support the Company's rate schedules.

8.6.2 If Company is providing MRSP functions for the ESP, pursuant to the Rules, meters must be compatible with Company's meter reading system.

8.6.3 No meter or associated metering equipment shall be set or allowed to remain in service if it is determined that the meter or its associated equipment did not meet approved specifications, as set forth in Company's ESRM, or is in violation of any code listed in Section 8.5.

8.7 Meter Testing

8.7.1 If a manufacturer's sealed meter has not previously been set and the meter was tested within the last twelve (12) months, the meter shall be deemed in compliance with ACC standards without additional testing.

8.7.2 Any meter removed from service shall be processed according to the following table prior to its re-installation:

METER TYPE	REMOVAL REASON	ACTION REQUIRED
1 Ph kWh Electro-Mechanical	Routine	Meter Inspection
1 Ph kWh Electro-Mechanical	Trouble	Meter Test
1 Ph kWh Hybrid or Solid State	Routine	Meter Test

1 Ph TOU (all)	Trouble	Meter Test
3 Ph Meters (all)	All	Meter Test
1 Ph or 3 Ph IDR Meters	All	Meter Test

8.7.3 Meter tests are to be conducted in accordance with ANSI C12.1 recommended testing standards.

8.7.4 Records on meter testing shall be maintained by the MSP and provided to the requesting parties within three (3) working days of such a request for such records. The latest meter test record shall be kept as long as the meter is in service.

8.8 Meter Test Requests

Pursuant to A.A.C. R14-209(F), either party may request that the other party perform a meter test, in which instance the requesting party is entitled to witness the test if it so chooses. The requesting party shall be notified of the test date and written test results from the testing party. If the meter is found to be within ACC-approved standards, the requesting party shall reimburse the other party for all costs incurred in the process of testing the meter (per ACC approved tariffs). The MSP shall take reasonable measures to detect meter error. The MSP shall notify Company as soon as it becomes aware of any meter that is not operating in compliance with ACC performance specifications. The MSP shall make any repairs or changes required to correct the error. ESPs and Company shall use a form approved by the ACC Process Standardization Working Group (PSWG) to initiate and respond to such action.

8.9 Meter Identification

8.9.1 The ESP or its agent shall install a Company provided unique number on each meter. Company will provide the unique numbers printed on stickers in blocks of up to 1,000 numbers. These stickers must be readily visible from the front of the meter. The number assigned to that meter shall remain solely with that meter while in use in Company's service territory.

8.9.2 When an ESP installs either its own meter or a customer owned meter, the ring or lock ring must be secured with a blue seal that is imprinted with the name and/or logo of the ESP or their agent.

8.10 Installation of metering equipment

8.10.1 All metering equipment shall be installed according to all applicable ACC requirements and Company's Electric Service Requirements Manual.

8.10.2 An ESP or its agent must be authorized by Company to remove a Company owned meter. The Existing Meter Information (EMI) form will be sent to the ESP and MSP within five (5) working days within receiving the DASR acceptance notification indicating a pending meter exchange. When the MSP intends to remove a Company meter, Company must receive a Meter Data Communication Request (MDCR) format at least five (5) working days prior to the exchange. Upon completion of the meter exchange, the MSP will return the Meter Installation/Removal Notification (MIRN) form to Company by the end of business, three (3) working days from the day of the exchange.

8.10.3 The ESP or its agent shall inform Company of all meter activity, such as meter installations or exchanges, via the Meter Activity Coordination (MAC) Form within the time frames specified above. If final meter reads are not provided to Company, are inaccurate, or otherwise result in Company not being able to render accurate final bills to customers pursuant to ACC Rules and Regulations, the ESP shall be responsible for any unbilled, disputed, or unrecoverable amounts and applicable late charges.

8.10.4 The ESP or its agent shall return the existing meter to Company at one of Company's designated locations identified in the meter drop off list within fifteen (15) working days after its removal, or be charged the cost of the meter and metering equipment and /or any other charges per the applicable ACC-approved tariff. The ESP or its agent shall be responsible for damage to the meter occurring during shipment.

8.11 On-Site Inspections/Site Meets

8.11.1 Company may perform on-site inspections of meter installations. The ESP shall be notified if the inspections uncover any material non-compliance by the MSP with the approved specifications and standards.

8.11.2 For new construction, the party installing the meter shall ensure that the owner/builder has met the construction standards outlined in Company's ESRM, and Company's Transmission and Distribution construction manual, as well as local municipal agency requirements, and any updates, supplements, amendments and other changes that may be made to these manuals and requirements.

Company shall perform a preinstallation inspection on all new construction. Local city/county clearances may also be required prior to energizing any new construction.

8.11.3 Company may require a site meet for: the exchange or removal of an IDR meter which requires an optical device to retrieve interval data; the exchange or removal of equipment at an existing totalized metering installation; a restricted access location for which Company forbids key access; cogeneration sites, bi-directional or detented metering sites; or upon request of an ESP or MSP. The ESP and Company's MAC shall coordinate the time of the site meet. If the ESP or MSP miss two (2) site meets, Company may cancel the applicable DASR. Company may charge for a site meet requested by the ESP or MSP, or if the ESP or MSP fails to arrive within thirty (30) minutes of the appointment time, or if the ESP fails to cancel a site meet at least one (1) working day in advance of the appointment time.

8.12 Meter Service Options and Obligations

8.12.1 Meter Ownership shall be limited to Company, an ESP, or the customer. The customer must obtain the meter through Company or an ESP. Although a customer may own the electric meter, maintenance and servicing of the metering equipment shall be limited to Company, the ESP, or the ESP's qualified representative (MSP).

8.12.2 If the ESP or customer owns the meter, the ESP must own the CTs, PTs, and associated equipment, except as provided in Section 8.12.3. The ESP may purchase existing CTs and PTs and associated metering equipment from Company at depreciated original cost.

8.12.3 The following provisions apply to the ownership of CTs and PTs.

8.12.3.1 For distribution voltages up to 25kV, the ESP or Company shall own the CTs and PTs. For transmission primary voltages (over 25kV), the CTs and PTs shall be owned by Company. ESP owned CTs and PTs must meet Company specifications. No CTs and PTs or associated metering equipment shall be set or allowed to remain in service if it is determined that the CTs and PTs or their associated equipment does not meet Company's approved specifications, as set forth in Company's Electric Service Requirements Manual in place at the time of installation.

8.12.4 All CT-rated meter installations shall utilize safety test switches, and all self-contained commercial metering shall utilize safety-test blocks as provided in Company's ESRM. During meter exchanges, the ESP or its agent's employees who are certificated to perform the related MSP activities may install, replace or operate Company test switches and operate Company-sealed customer-owned test blocks.

8.13 Installation Options

8.13.1 The ESP is responsible for Direct Access customer meter installation and associated cost. Company may optionally provide meter installation pursuant to the provisions of this Service Schedule.

8.13.2 ESPs or their agents must be certificated by the ACC in order to offer MSP services. The policies and procedures described in this Section 8.13 assume that the MSP and their meter installers have ACC certification. ESPs may elect to offer metering services by:

8.13.2.1 Becoming a certificated MSP.

8.13.2.2 Subcontracting with a third party that is a certificated MSP.

8.13.2.3 Subcontracting with Company under the circumstances described in Section 8.2.

8.14 As part of providing metering services, ESPs or their agents shall:

8.14.1 Obtain lock ring keys for meters originally installed by Company or request site meets with Company. Company will issue lock ring keys to certified MSPs upon receipt of a refundable deposit. The deposit will not be refunded if a key is either lost or stolen, and a fee will be applied to replace lost or damaged keys. For more information about the cost of lock rings, standard rings, or lock ring keys, please consult the Company MAC.

8.14.2 If lock rings are used they shall meet Company requirements. If a meter is installed and the readings are obtained from a source other than a physical inspection, a lock ring must be utilized. Lock rings may be purchased from Company.

8.14.3 Provide information to Company on the specifications and other specifics on meters not purchased from or installed by Company.

8.14.4 Allow Company to remove the customer's meter, or schedule a site meet to remove the meter transferring from Direct Access to Standard Offer service. If the ESP allows Company to remove meters, ESP shall coordinate with Company regarding the return of the meters.

8.14.5 Be responsible for obtaining and providing reads from any meter that it installs from the time it is installed to the time it is removed or until meter reading responsibilities are assumed by another ESP or the customer returns to Standard Offer service.

8.14.6 Ensure that ESP and MSP employees working in Company's territory follow ACC and other applicable safety standards.

8.14.7 Company shall notify the ESP immediately and the ESP shall notify Company immediately of any suspected unauthorized energy use when a safety hazard exists. In instances where there is not a safety hazard, each party will notify each other within twenty-four (24) hours. The ESP shall ensure that a lock ring is installed to secure any meter that does not require a monthly local (i.e., manual) meter read. The Parties agree to preserve any evidence of unauthorized energy use. Once unauthorized energy use is suspected, Company, in its sole discretion, may take any or all of the actions permitted under Company's tariffs and schedules and shall notify the ACC of any such action taken.

8.14.8 Take no action to impede Company's safe and unrestricted access to a customer's service entrance.

8.14.9 Glass over any socket when a meter is removed and a new meter is not installed.

8.15 MSRP Services provided as a responsibility of an ESP

Only certificated MRSP's acting on the ESP's behalf in accordance with ACC regulations shall perform MRSP functions. The MRSP for each Direct Access customer will be specified on the DASR received from the ESP. Any changes to Customers MRSP will be updated by the ESP with a "UC" DASR at least ten (10) days prior to the next scheduled read date. MRSP obligations and responsibilities are stated in the ACC's Rules and Regulations and include:

8.15.1 Meter data for Direct Access Customers shall be read, validated, edited, and transferred pursuant to Arizona's Validation, Editing, and Estimation Process (VEE). It is the responsibility of the MRSP to comply with this process. In cases where validated data is unavailable for transfer by the posting deadline, it is the responsibility of the MRSP to provide an estimated data file for the entire read cycle until actual meter data is available. At such time as actual data becomes available, a corrected data file shall be posted immediately.

8.15.2 Both Company and the ESP shall have 24-hour/7 days per week access to the MRSP server.

8.15.3 Meter read data shall include beginning and ending reads as well as the validated usage for load-profiled customers. Validated interval data shall be provided for all interval metering customers. Data must be posted to the MRSP server using the Arizona Standard EDI "867" format. Estimated data shall contain applicable reason codes pursuant to the 867 guidelines.

8.15.4 The MRSP shall provide Company with access to meter data at the MRSP server as required to allow the proper performance of billing and settlement.

8.15.5 MRSPs must have a CC&N from the ACC authorizing it to offer MSRP services, and must be certified in Company territory.

8.15.6 MRSPs shall read Customer's meter based on the scheduled read date per Company's Yearly Meter Read Schedule. The billing cycle for each meter shall contain the full period from read date to the following read date. Interval data cycles shall be considered from 00:15 on the read date to 00:00 on the following read date (i.e. 9/1/00 00:15 through 10/1/00 00:00). The first complete interval timestamp shall begin at 00:15 in each cycle. For meter exchanges to Direct Access, the first complete interval through the first read date at 00:00 shall constitute the billing cycle. For meter exchanges back to Standard Offer, every interval shall be included up to the last full interval

prior to the exchange. It is the responsibility of the MRSP to provide estimation of any intervals that are necessary to constitute the full billing cycle.

8.15.7 The MRSP shall provide re-reads or read verifies within ten (10) working days of a request by Company or Customer. The requesting party may be charged per the applicable ACC tariff if the original read was not in error.

8.16 Meter Reading Data Obligations

8.16.1 Accuracy for all meters

8.16.1.1 Meter clocks shall be maintained according to Arizona time within +/- three (3) minutes of the National Time Standard.

8.16.1.2 Meter read date and time shall be accurate.

8.16.1.3 All meter reading data shall be validated pursuant to the approved Arizona VEE guidelines.

8.16.2 Timeliness for Validated Meter Reading Data

Pursuant to guidelines established by the Utilities Division Director, one hundred percent (100%) of the validated meter data shall be available by 3:00 p.m. Local Arizona Time (MST) on the third working day after the scheduled read date. If the meter data is not posted, is unavailable, or clearly contains errors by this deadline, the billing determinants including usage (kWh) and demand (kW) may be estimated by Company and the ESP shall be charged an approved charge for this service.

8.16.3 Proof of Operational Ability

Prior to performing MRSP services in Company's distribution service territory, or prior to making any significant change in MRSP service methodology, each MRSP will perform compliance testing to demonstrate its ability to read meters, validate data, edit data, estimate missing data and post validated data in Company-compatible EDI format to the MRSP server. In addition, upon installation of the initial meter on Direct Access accounts in Company's distribution service territory, each MRSP shall prove its ability to read its meters and post validated data in Company-compatible EDI format to the MRSP server. If the MRSP is unsuccessful in its attempts to meet these requirements, all subsequent requests for meter exchanges will be postponed until the MRSP successfully demonstrates its operational ability.

8.16.4 Retention and Format for Meter Reading Data

8.16.4.1 All meter reading data for a Customer shall remain posted on the MRSP server for five (5) working days and will be recoverable for at least three (3) years.

8.16.4.2 Meter reading data posted to the MRSP server shall be stored in Company-compatible EDI format.

8.17 Company performing MSP and MRSP functions:

If Company is eligible to perform Direct Access related MSP and MRSP functions as defined in section 8.2, the following restriction applies:

The validated meter read will be posted in EDI format no later than 6 working days following the scheduled read date.

8.18 Non-Conforming Meters, Meter Errors and Meter Reading Errors

8.18.1 Whenever Company, the ESP or its agents becomes aware of any non-conforming meters, erroneous meter services and/or meter reading services that impact billing, it shall promptly notify the other parties and the affected Customer. Bills found to be in error due to non-conforming meters or errors in meter services or meter reading services will be corrected by the appropriate parties.

8.18.2 In cases of meter failure or non-compliance, the ESP or its agents shall have five (5) working days to correct the non-compliance. If the non-compliance is not remedied within five (5) working days, the following actions may apply:

8.18.2.1 A site meeting may be required when services are being performed. The non-compliant party may be charged an ACC-approved tariff for the meeting.

8.18.2.2 Company may repair the defect, and the other party shall be responsible for all related expenses.

8.18.2.3 Company shall adhere to the approved Performance Monitoring Standards and follow the steps outlined to address non-compliance by an MRSP.

8.18.3 Company may refuse to enter into a new ESP Service Acquisition Agreement, or cancel an existing ESP Service Acquisition Agreement pursuant to section 7.10.1.2, with any ESP or its agents that has a demonstrated pattern of uncorrected non-compliance as established above. This provision shall not apply if the alleged demonstrated pattern of non-compliance or correction thereof is disputed and is pending before any agency or entity with jurisdiction to resolve the dispute.

Schedule 15

SERVICE SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION OF SPECIALIZED METERING

Arizona Public Service Company (Company) will provide specialized metering upon customer request, provided the customer agrees to the following conditions:

1. The customer must contact their Company Account Representative to request and coordinate the purchase and installation of specialized metering such as KYZ pulse meters, IDR meters, or IDR meter with KYZ pulse and/or modem options (including associated interfaces).

2. If the customer requests a meter with a modem option, the customer will be required to install coil of communication cable within five feet of the meter panel location and in such a manner that will provide for ease of attachment to the meter panel by Company. The phone line must be installed prior to the installation of the meter and shall be located in such a manner as to not impede access to the metering equipment, the interior or exterior of the metering compartment or other utility access panels. The customer must provide Company with a phone number and any other communication access information to the meter(s) prior to Company installation of the meter(s).

3. If a customer requests kWh pulses, Company shall furnish and install a customer pulse interface and enclosure. Connections made by the customer to the customer pulse interface shall not impede access to metering equipment, the interior or exterior of the metering compartment or other utility access panels.

4. The customer will be required to make a non-refundable contribution in aid of construction to Company for the requested meter(s) installation. The non-refundable contribution amount will be determined at the time of the request as follows:

   4.1 If a meter currently exists on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less the equipment cost of Company's existing meter.

   4.2 If a meter has not been installed on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less 100% of the AUC cost of a Company standard meter.

   4.3 If a specialized meter is existing on a customer's site and the customer requests an upgrade to a different type of meter, the customer will be responsible for 100% of the cost (installation and equipment) associated with the requested meter.

   Company will not place an order for a requested meter(s) until payment has been received from the customer. The typical lead time for procurement of meters is six (6) to eight (8) weeks. Once the requested meter(s) have been received, Company will schedule the installation of the meter(s) with the customer or a designated representative.

   Company will retain ownership of all meters and Company installed metering equipment.

   If a customer makes a nonrefundable contribution for the installation of a specialized meter and then terminates service or requests Company to remove and/or replace the specialized meter, the customer will not be eligible for a refund.

   Company will provide general maintenance of the specialized meter; however, in the event the meter should become damaged, obsolete or inoperable, the customer will be responsible for 100% of the replacement cost (installation and equipment) associated with the specialized meter.

Company will not be responsible for the installation, maintenance, or usage fees associated with any phone lines or related communication equipment.

5. Under no circumstances shall the customer stop the operation or in any way affect or interfere with the operation of the customer pulse interface and the related output wiring. The integrity of Company's billing metering equipment within the sealed metering compartment shall be maintained.

6. Company reserves the right to interrupt the specialized metering circuit for emergencies or to perform routine or special tests or maintenance on its billing metering equipment, and in so doing assumes no responsibility for affecting the operation of the customer's demand control or other equipment. However, Company will make a good faith effort to notify the customer prior to any interruption of the specialized metering circuit.

7. The possible failure or malfunction of an KYZ pulse output or interface and subsequent loss of kWh contact closures to the customer's control equipment shall in no way be deemed to invalidate or in any way impair the accuracy and readings of Company's meters in establishing the kWh and demand record for billing purposes.

8. The accuracy of the customer's equipment is entirely the responsibility of the customer. Should the customer's equipment malfunction, Company will reasonably cooperate with the customer to the extent of assuring that no malfunction exists in Company's equipment. Work of this nature will be billed to the customer, unless the actual source of the malfunction is found within Company's equipment.

9. If Company provides pulse values in kWh, customer's equipment must be capable of readjustment or recalibration to adjust to new contact closure values and rates should it become necessary for Company to adjust the pulse values due to changes in Company's equipment.

10. No circuit for use by the customer shall be installed from Company's billing metering potential or current transformer secondaries.

11. Company reserves the right, without assuming any liability or responsibility, to disconnect and/or remove the pulse delivery equipment at any time upon 30 days written notice to the customer.

12. Upon request by Company, the customer shall make available to Company monthly load analysis information.

13. References to electric kWh pulses above shall mean dry KYZ contact closures only; the customer is required to furnish operating voltage service. KYZ contacts are rated for and shall not be wetted beyond a maximum of 100 milliampere and 120 volts DC or AC rms.

14. The customer assumes all responsibility for, and agrees to indemnify and save Company harmless against, all liability, damages, judgments, fines, penalties, claims, charges, costs and fees incurred by Company resulting from the furnishing of specialized metering.

15. A waiver at any time by either party, or any default of or breach by the other party or any matter arising in connection with this service, shall not be considered a waiver of any subsequent default or matter.

16. Prior written approval by an authorized Company representative is required before electric kWh pulses service may be implemented.

Schedule 16

EXPERIMENTAL SERVICE SCHEDULE 16
HOME ENERGY INFORMATION PILOT

AVAILABILITY

This experimental service schedule is available through December 31, 2012 in the Phoenix area and other areas served by the Company that are designated to be part of the pilot program. Service Schedule 16 was approved by the Arizona Corporation Commission in Decision No. 72214.

APPLICATION

The Experimental Service Schedule 16 is applicable to residential retail standard offer customers with an Advanced Metering Infrastructure (AMI) meter in place at time of service. All provisions of the customer's current applicable rate schedule will continue to apply in addition to the provisions in Service Schedule 16. The participating customer is requested to continue service under the pilot program through December 31, 2012, but may discontinue participation at any time.

The pilot program shall consist of five options with associated technology devices and eligible rate schedules. Participation shall be limited to a total of 2,800 customers capped at the designated participation level for each option. However, the Company, at its discretion, may oversubscribe participation to allow for potential dropouts during the pilot period.

Option	Description	Eligible Residential Rate Schedules	Participation
A	Critical Peak Pricing with Customer Energy Control Device	E-12, ET-1, ET-2, with rider CPP-RES	0-300
B	In-home Energy Information Display	E-12, ET-1, ET-2, ET-SP	0-300
C	Smart Thermostat or Control Switch with APS Direct Load Control of Air Conditioner	E-12, ET-1, ET-2	0-300
D	Qualifying Smart Phone, Personal Digital Assistant, and Computer Energy Information	E-12, ET-1, ET-2, ET-SP	0-300
E	Pre-pay Energy Service	E-12, E-12 Low Income, ET-1, ET-1 Low Income, ET-2, ET-2 Low Income, ET-SP	600-2,000

In addition, to be eligible for Options A, B and C the customer must own and reside in the home associated with the pilot program, and their average computed monthly bill during June through September must be $150 or greater. Customers participating in Option D must own a qualifying smart phone, personal digital assistant or computer with required broadband service.

Customers participating in Option E must have an AMI remote disconnect function and may not participate in rider rate schedules CPP-RES, GPS-1, GPS-2, Solar-3, EPR-2, EPR-6 and E-4, or direct debit and budget billing programs. Option E shall only be available to customers for which pre-payment is a reasonable and appropriate option. Eligible customers shall be provided the rules and requirements of Pre-pay Energy Service and must confirm their full understanding of this information prior to enrolling in the service. In addition, the Company shall ensure that appropriate protections are in place for elderly and low-income customers. Customers enrolled in the Company's Medical Care Preparedness Program, may not participate in this offering.

DESCRIPTION OF SERVICES

Option A – Critical Peak Pricing with Customer Energy Control Device

Company shall provide a device in the customer's home that enables the customer to control their home energy usage to provide an automated response to critical peak pricing under Schedule CPP-RES. APS shall communicate to device to activate the customer's pre-programmed response during critical events. Customer may override the response.

Option B – In-home Energy Information Display

Company shall provide a device in the customer's home that displays various energy usage and cost information.

Option C - Smart Thermostat or Control Switch with APS Direct Load Control of Air-conditioner

The Company will install a smart thermostat or control switch in the customer's home that will allow the Company to modify the thermostat settings through a remote signal in order to reduce the customer's energy usage during hours of extremely high electrical demand, high temperature, major generation or transmission outage, energy market disruptions, or other critical events.

Customer agrees to have a smart thermostat control device or switch installed in their home at Company expense and to allow the Company to remotely control their thermostat setting during high summer peak hours in accordance with the Direct Load Control Program Guidelines, which may be revised by the Company from time-to-time during the pilot program with notification to the customer.

Option D – Qualifying Smart Phone, Personal Digital Assistant and Computer Energy Information

Company shall provide an application for the customer's qualifying smart phone, personal digital assistant, or computer that will provide energy cost and usage information.

Option E – Pre-pay Energy Service

The Company provides customers a billing option, feedback on energy usage, and energy conservation information to enable participants to better understand and manage their energy consumption, costs, and payments.

The customer periodically pre-pays an amount towards their electric service in lieu of paying a monthly bill. The Company provides the customer with updated energy usage, cost, and account balance information to assist them in managing their energy dollars. The Company alerts the customer when their account balance falls below a threshold level. Customer agrees to the provisions of pre-pay service provided in the Pre-pay Energy Service Program Guidelines, which may be revised by the Company from time-to-time with notification to the customer. The Company shall solicit a minimum of 600 participants to study the impact of pre-pay service on their monthly energy consumption. The sample will be adequate to reliably represent low income and elderly customer segments.

(DESCRIPTION OF SERVICES, Con't...)

Participants of Pre-pay Energy Service will not receive written notice of disconnection. Therefore, A.A.C. R14-2-211 is waived for this service. However, the Company's existing disconnection protections with respect to extreme weather events shall apply to this service. Pre-pay Energy Service shall be provided according to the terms and conditions of Service Schedule 1 and the Pre-pay Energy Service Program Guidelines. In case of a conflict, the provisions of the Pre-pay Energy Service Program Guidelines shall apply.

TERMS AND CONDITIONS

1. The customer agrees to have the specified device or application installed in their home, smart phone, personal digital assistant or computer, as applicable, at Company expense.
2. The Company may substitute other smart devices in lieu of or in addition to a smart thermostat or in-home devise as agreed to by the customer.
3. The customer may be required to sign a participant agreement as applicable.
4. The customer agrees to participate in marketing research conducted as part of the pilot program.
5. Customer may keep the device or application, as applicable, at the end of the program if they participate through December 31, 2012.
6. For customers who continue participation in the pilot program through December 31, 2012, the Company shall provide a home energy audit, or comparable offering, at no expense to the customer. For Option E, the energy audit, or comparable offering, will be limited to the customers who are solicited by APS to study their monthly energy impacts.
7. If customer discontinues participation prior to December 31, 2012, the Company shall remove the device or application, as applicable, at Company expense.

Donald G. Robinson

TESTIMONY OF DONALD G. ROBINSON

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-_____

June 1, 2011

Table of Contents

I. INTRODUCTION. 1
II. SUMMARY 2
III. APS FUNDAMENTALS 5
IV. PROJECTS TODAY BENEFIT FOR THE LONG TERM. 8
V. CONCLUSION. 14

TESTIMONY OF DONALD G. ROBINSON
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-____)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Donald G. Robinson. My business address is 400 North 5th Street, Phoenix, Arizona 85004. I am President and Chief Operating Officer of Arizona Public Service Company ("APS" or "Company"). In that capacity, I am responsible for all aspects of APS operations, including fossil generation, transmission, distribution, customer service, marketing and trading, resource planning, renewable resources, energy efficiency, and general administrative functions.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I joined APS in 1978, in the Company's accounting department. In 1981, I became the Manager of Regulatory Affairs and in 1996, Director of Pricing, Rates, Regulation, and Planning. In 2001, I was named the Vice President of Regulation and Planning of Pinnacle West Capital Corporation, and was responsible for regulatory policies and activities before the Arizona Corporation Commission ("Commission") and the Federal Energy Regulatory Commission ("FERC"), as well as for corporate planning. I was thereafter named Senior Vice President of Administration and Planning of APS. I assumed my current role in 2009.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. My testimony describes APS: the role we play in our Arizona communities, where we are headed as a leader in Arizona energy, and why approval of this rate filing is critical to getting us there.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. This is a time of remarkable challenges and exceptional opportunities for both the electric power industry and APS. Technology improvements and cost efficiencies are making renewable resources a growing part of meeting electricity demand, but require changes to how we operate our electric system. Energy efficiency is being embraced in Arizona and around the country as an affordable resource, but is causing slower (and sometimes even negative) load growth – an impact that requires modern rate designs that will allow utilities to both maximize the anticipated benefits of efficiency and recover their fixed costs of service. An aggressive set of new pollution control regulations is poised to have a profound effect on our nation's power generation fleet. At a time when the electric industry needs to access large amounts of capital, credit ratings agencies are being subject to increasing government scrutiny and financial regulation, causing them to rate utility credit quality more conservatively than in the past. I see more changes affecting our industry today than at any time in my 30 years of experience.

We know that electricity is essential to our customers and that we must constructively address these many challenges. Doing so compels us to look to the future and plan for the long-term, recognizing that proactive planning requires investments in new resources, technology and infrastructure today. At the same time, we intend to maintain our proven track record of superior operating performance and explore new ways to serve customers reliably and efficiently.

APS is fully committed to the programs that have been established to achieve Arizona's energy goals, but we need the Commission's support to continue our progress. A sustainable energy future requires a long-term focus and constructive

regulatory support—such as that embodied in APS's 2009 rate case Settlement Agreement ("Settlement").[1] The Settlement set clear renewable energy and energy efficiency goals for APS, which we are meeting. The Settlement also recognized that the cost required to achieve these goals and provide reliable electric service must be adequately reflected in our prices. Towards that end, the Settlement took steps to modernize the ratemaking processes with a goal of making more gradual and predictable rate changes over time, rather than requiring sporadic and dramatic rate hikes. It put APS on a two-phase rate case filing plan that lasts until 2014 and funded the energy policy goals set in the Settlement through 2012. Recognizing that the Company would need additional funding thereafter to continue meeting Arizona's goals for energy efficiency, renewable energy and system reliability, the Settlement authorized a June 1, 2011 filing date for this rate case and provided that parties should work to resolve it by July 2012.

Working from that framework, this application proposes new tools that further adapt the Company's rate structures to meet today's needs and continue the work that started with the Commission and 22 Settlement signatories in 2009. Our proposals define a long-term strategy to continue to bring APS customers the high levels of reliability they expect, outstanding customer service, comprehensive energy efficiency and renewable energy programs, and needed upgrades to our electric system.[2] As proposed, these benefits would be funded through progressive rate mechanisms that will more gradually impact customer bills and bring more stability and predictability in the long run. If APS's requests are approved, customer bills would initially increase by about 6.6% on average.

---

[1] Approved in Decision No. 71448 (December 31, 2009).

[2] In his testimony, APS Vice President of Rates and Regulation Jeff Guldner describes the specifics of the Company's requests.

We are keenly aware of the challenges facing our customers and Arizona's economy. To that end, we have aggressively implemented cost management programs. Since the 2009 Settlement, we have achieved more than $37 million in cost-savings during the 2010 Test Year, thereby meaningfully reducing our rate request in this filing. Our operational expenses have remained virtually flat since the Settlement Agreement was approved and do not drive this rate request. We continue to look for new ways to manage costs and operate more efficiently without compromising reliability or customer service.

To lessen the bill impact of our rate application, we have also voluntarily excluded from our base rate calculation various portions of our cost of service that we have traditionally requested and are entitled to recover. Our filing also enables APS customers to benefit from significant energy efficiency offerings so that they may better manage their energy use and keep their bills down. Finally, our filing proposes a new rate offering specifically designed to promote cost-effective economic growth and development throughout the State.

The Commission's approval of the Settlement signaled a willingness to provide the support APS needs to achieve Arizona's energy goals and build a sustainable energy future for our State. Equally powerful was the demonstrated consensus among the Settlement's signatories that APS cannot accomplish this result unless Arizona's traditional regulatory framework adapts to keep pace with the fast-moving opportunities and challenges facing the electric industry today. That framework is widely viewed as a milestone that set the stage for positive developments in Arizona energy policy. This request seeks to continue that momentum and take further steps to make Arizona's energy landscape sustainable for the long term.

III. APS FUNDAMENTALS

Q. PLEASE GIVE A BRIEF OVERVIEW OF APS.

A. APS is Arizona's largest and longest serving electric utility, serving Arizona's growing population since 1886. APS has about 6,800 employees and serves more than 1.1 million retail and wholesale customers in all or part of 11 of Arizona's 15 counties – a service territory of approximately 35,000 square miles. APS owns more than 33,000 miles of transmission and distribution lines and underground cable to deliver this energy to our customers. We also co-own and operate the Palo Verde Nuclear Generating Station ("Palo Verde"), a primary source of electricity for the Southwest and the largest nuclear generation facility in the United States, as well as two coal-fired plants and six natural gas plants. At present, APS generates more than three percent of its electricity from renewable resources, a number that we expect to grow to 16% by 2025. By 2015, we expect to have a renewable portfolio of over 1200 MW, enough renewable energy to serve roughly 10% of our retail sales.

Q. WHAT ECONOMIC IMPACT DOES APS HAVE ON ARIZONA?

A. A significant one. With an extensive network of power plants, transmission and distribution lines, customer offices and support facilities, APS is the largest property taxpayer in the State by a significant margin, infusing approximately $128 million of property tax in 2010. This amount almost doubles the in-lieu-of tax payment of Salt River Project, Arizona's second largest taxpayer. Last year, the Company purchased from more than 6,000 Arizona suppliers and spent approximately $620 million on goods and services offered by Arizona businesses.

Due to the extensive construction of electric infrastructure necessary to maintain the Company's existing system and meet future demand, APS is among the State's largest construction companies. In 2010 alone, APS infused approximately $660 million into Arizona's economy as part of its ongoing

construction program. Next year, that number is projected to reach approximately $1 billion, and will likely be close to $20 billion through 2025. APS generates more jobs than most other Arizona corporations, providing employment to almost 6,800 Arizonans, directly creating jobs for thousands of contractors, and indirectly creating tens of thousands of additional jobs throughout the State. Roughly 2,000 of APS's employees and contractors are members of local unions. We are also one of the few S&P 500 companies with headquarters in Arizona. A Study prepared by the L. William Seidman Research Institute of the WP Carey School of Business discusses the Company's economic impact on Arizona in further detail, and is available on the APS website (aps.com).

Q. WHAT DOES APS VIEW AS ITS CORE RESPONSIBILITIES?

A. At APS, our mission is to "safely and efficiently generate and deliver reliable electric power and related services to our customers" – and we are recognized for performing that task well. In 2010, for example, APS's operational performance placed it in the top-quartile among its peers under each of the standard industry measures of distribution system reliability (such as outage frequency and average outage duration). As Liberty Consulting Group ("Liberty") observed in its recent benchmarking study that compared APS's operational performance to industry peers ("Liberty Benchmarking Study"), APS "rates far better than the industry average" on standard reliability metrics and "the favorable gap is growing with time."[3] APS also remains a consistent top-quartile industry performer in terms of outages per customer. In 2010, APS customers experienced an average of 0.90 outages per customer, compared to an industry median of 1.07.

APS also excels in terms of customer satisfaction. In July of 2010, J.D. Power and Associates ranked APS third of the 55 investor-owned utilities in its group for Residential Customer Satisfaction. In its associated webcast, J.D. Power

[3] *See* Liberty Benchmarking Study at 10.

featured APS as a top performer nationally, standing the Company apart from the other utilities in the mix. The Liberty Benchmarking Study concluded similarly, noting that – using factors such as price, billing and payment, power quality and reliability, and customer service as metrics– "APS ranks high in customer satisfaction," particularly vis-à-vis other investor owned utilities (where, Liberty finds, APS ranks 4 of 89).[4] Liberty also noted an upward trend in the Company's customer satisfaction scores, highlighting that APS "has risen to mid-top quartile from mid-second quartile just three years ago."[5]

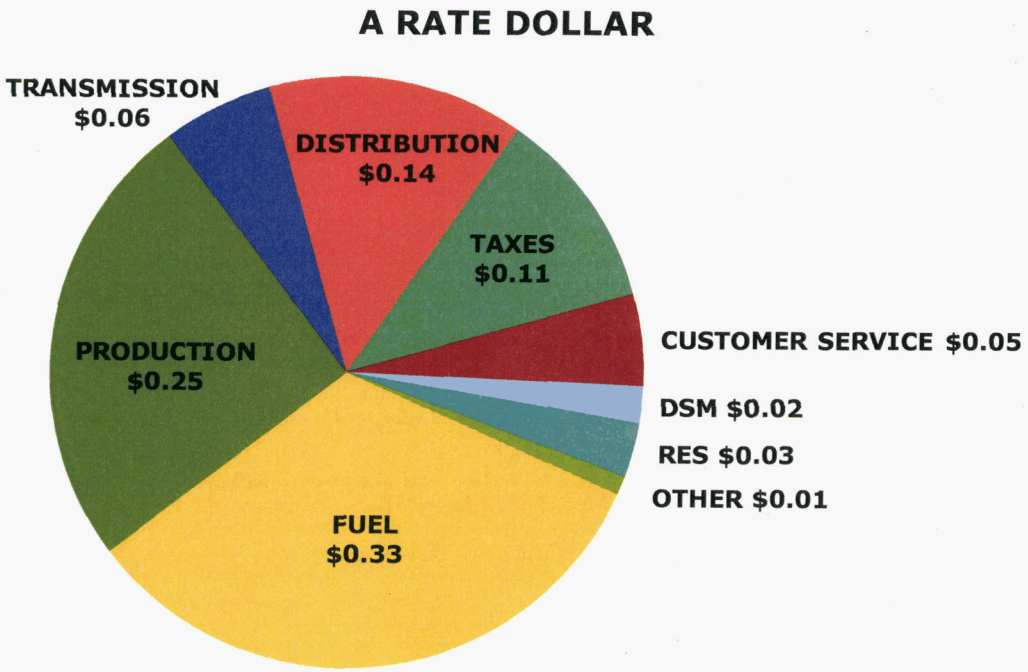
While APS has always compared favorably to the industry generally in terms of safety,[6] 2010 marked APS's safest year on record – the third straight year of discernible improvements in the Company's recordable injuries. Our concerted emphasis on and employee commitment to safety has resulted in first-quartile safety performance. We expect that our continued focus on this value will result in improved safety performance going forward.

APS is also firmly committed to making our product and services cost-effective for customers. We do this in large part by intensely managing costs and operating efficiently. While APS has always focused on cost-management, we have intensified that effort in recent years through a cost management initiative that saved over $37 million of expenses in 2010 alone – an achievement that reduced the rate request made in this proceeding. In fact, the Company's aggressive focus on cost containment and operational efficiency has allowed us to keep our operational expenses relatively flat over the past several years. This is an impressive feat given the challenges and cost increases facing our industry today.

---

[4] *See* Liberty Benchmarking Study at 9.
[5] *See id.*
[6] See Liberty Benchmarking Study at 8.

These are but a few of several examples that demonstrate APS's commitment to getting the basics – our core responsibilities – right for our customers. And, as the following demonstrates, the overwhelming majority of every dollar that a customer spends on its APS bill pays for the costs required for us to do just that.



IV. PROJECTS TODAY BENEFIT FOR THE LONG TERM.

Q. YOU NOTED EARLIER THAT THE COMPANY STRIVES TO BUILD A SUSTAINABLE ENERGY FUTURE FOR ARIZONA. WHAT DOES THAT MEAN TO APS?

A. At APS, sustainability means meeting Arizona's energy needs by implementing a business strategy that supports superior operating performance, efficiency, a healthy environment, a vibrant economy, and a strong community. When these goals compete, as they sometimes do, it means taking a long-term view to determine what path today best serves the generations of tomorrow. The Settlement took important steps down that path, which APS seeks to continue.

Q. PLEASE PROVIDE SOME EXAMPLES OF WHAT APS IS DOING NOW TO MAKE ARIZONA'S ENERGY LANDSCAPE SUSTAINABLE.

A. APS's focus on sustainability is demonstrated by the investments we make. Our distribution and generation upgrades improve system reliability; renewable energy and energy efficiency investments grow those resources' contribution to a balanced energy portfolio; and new tools enable customers to manage and understand better their energy use. In short, the programs and projects on which we spend capital dollars improve Arizona's energy landscape for the long term. APS's witnesses Daniel Froetscher (Vice President of Energy Delivery), Mark Schiavoni (Senior Vice President of Fossil Generation), and Randy Edington (Executive Vice President and Chief Nuclear Officer) will address the details of many of the Company's capital investments in their respective testimonies. I would like to highlight a few key examples here, all specific to the 2010 Test Year.

On the resource front, APS signed contracts to develop the first 83 MW of the 100 MW of utility-scale solar photovoltaic power plants authorized as part of the AZ Sun program. APS will finance and own these generating facilities, which are being designed and constructed by third party developers. Five contracts are now underway, and include a 17 MW Paloma solar plant in Gila Bend, a 17 MW Cotton Center solar plant in Gila Bend, a 16 MW Hyder solar plant east of Yuma, a 19 MW solar plant in Chino Valley, and a 14 MW solar plant at Luke Air Force Base. Collectively, these projects will produce enough solar energy to power roughly 20,750 homes, and will create roughly 625 temporary and permanent jobs in Arizona. Because of investments like these, APS estimates that 26% of customer growth through 2025 will be served by solar energy.

In line with our customer service focus, customers who participated in our energy efficiency programs during 2010 saved over $30 million on their electric bills.

These savings resulted from such Company programs as replacing incandescent lights with compact fluorescent lights, installing variable speed pool pump motors, recycling old inefficient refrigerators, and having their home's duct system inspected and repaired. Another interesting example: APS launched the "APS Outage Center" on Twitter on June 1, 2010, the Company's largest foray into social media. This tool allows APS to communicate directly to customers affected by outages about such things as the outage's size, areas affected, and restoration progress. In some cases, merely providing the update or reminding our "twittering" customers that APS crews were hard at work to restore their power put customers at ease.

As to energy delivery, no example better demonstrates the Company's commitment to delivery system reliability than does our response to the severe winter storms that lashed through the APS service territory early last year. Winds as high as 70 miles per hour drove heavy snow and torrential rain, downing power lines, snapping poles, and damaging towers throughout our system. APS crews responded rapidly and effectively to rebuild the system and restore power (crews even participated in a search and rescue effort to locate a missing family with young children). The vast majority of customers regained power within a few hours, although outages in some of the more remote locations lasted up to four days. Customers praised our crews for their dedication and professionalism despite the treacherous weather conditions.

On the generation reliability front, 2010 saw the last two of the new reactor vessel head installations needed on each of Palo Verde's three units, thus completing the power plant's major equipment upgrades. The new reactor vessel heads have specific qualities that make the equipment easier to maintain and will improve equipment performance. Replacing all three reactor heads at Palo Verde

is expected to increase the plant's reliability and improve its overall operating performance.

On the transmission side, a new 27 mile transmission line connecting the newly completed 230/500-kilovolt (kV) Morgan Substation to the newly-expanded Pinnacle Peak Substation was energized in December 2010. The $207 million construction project will provide needed transmission infrastructure to support growth in the north part of the Valley and improve the Company's overall transmission system reliability. As noted in the Company's Renewable Transmission Action Plan (approved by the Commission in 2010), this line will also facilitate the delivery of renewable energy to the Valley.

Q. DO YOU HAVE ANY OTHER EXAMPLES OF APS'S COMMITMENT TO SUSTAINABILITY?

A. Yes. As I described above, a key aspect of sustainability for APS is a strong dedication to our customers and the communities we serve. Although community outreach and economic development are not our core business, we strongly believe that it is our civic responsibility to do our part to engage with our communities and improve Arizona's economic condition.

Economic development is equally important to APS, particularly given our State's current economic climate. APS actively partners with several other economic development agencies (including, among others, the Greater Phoenix Economic Council, Central Arizona Regional Economic Development Foundation, and the Arizona Rural Development Council) in efforts to bring new companies to Arizona. Towards the same goal, this Application proposes a new economic development service schedule. If approved by the Commission, this new rate offering could promote new jobs and cost-effective business expansion for customers meeting defined eligibility criteria throughout our State. Mr. Charles Miessner describes this proposal in detail in his testimony.

APS is nationally recognized for our commitment to sustainability in these and other relevant areas. In March of this year, *Corporate Responsibility Magazine* ranked Pinnacle West Capital Corporation 15th overall on its annual list of "100 Best Corporate Citizens." The highest ranked of any utility, we received this prestigious honor because of APS's contributions in the areas of environment, climate change, employee relations, human rights, governance, and philanthropy. From our volunteers supporting children, education, the arts and culture; to our commitment to helping small and minority-owned businesses; to our encouragement of economic development, APS's strong dedication to corporate citizenship reflects its broader vision of supporting Arizona's future.

Q. WHAT ELSE IS APS DOING TODAY TO STRENGTHEN ARIZONA'S ENERGY FUTURE?

A. In a phrase, being proactive about our financial health. APS is Arizona's largest utility, and we must be financially strong so that we can continue to meet the State's energy goals cost-effectively. As Mr. Hatfield discusses, accessing the financial markets and securing financing on reasonable terms is by no means an easy feat, particularly in a tight economy. Like APS, utilities across the country are looking for the financing needed to upgrade their systems such that they will be less costly to maintain, more energy efficient and reliable, and more "green." The upward cost trend is more marked for Arizona utilities because, despite the current slow-down, Arizona remains a growth state. Thus, unlike many other utilities, APS must also invest in new plant and equipment to serve the new customers that join our system. Between now and 2025, we estimate that our customer base will grow by almost 550,000, rendering an overall customer count of close to 1.6 million. In total, APS's capital budget over the same period is close to $20 billion.

To finance these capital projects, APS must be able to compete effectively against the many other investor-owned utilities trying to do the same thing. Many of these utilities operate in regulatory jurisdictions that use future test years, allow automatic interim rate allowances, and use other mechanisms that reduce regulatory lag. As Mr. Hatfield discusses, the rates these utilities charge better track the utilities' pace of investment and reduce long-term customer prices, producing earned returns that are more attractive to potential investors compared to the returns generated when rates lag investment more significantly, such as under a historical test year regulatory model. To compete effectively against these utilities for capital, APS must be able to produce comparable returns.

The Settlement recognized this need and took steps to modernize APS rates as needed for APS to continue to serve customers reliably and finance Arizona's energy goals. Those steps were noticed by the financial world. As Mr. Hatfield notes, APS's bond rating may be upgraded if the ratings agencies perceive that the current trend of regulatory support will continue into the future.

Q. HOW ELSE IS APS BEING PROACTIVE ABOUT ITS FINANCIAL HEALTH?

A. As I earlier noted, APS has undertaken a significant cost management and operational efficiency initiative that has resulted in at least $37 million of cost savings in 2010.[7] We take this initiative seriously, as evidenced by our ability to keep operational expenses generally flat for the past several years – a remarkable accomplishment given the demands facing APS and the electric industry as a whole.

[7] APS identified the specific components of these cost-savings in a letter filed in Docket E-01345A-08-0172 on April 29, 2011.

Although cost management is critical, it is not enough to offset the need to invest in our system. Like everything, providing our customers with reliable electric power, reliable energy delivery, high levels of customer service, energy efficiency, and renewable energy comes at a price. As Mr. Hatfield explains, cost management simply cannot substitute for timely recovery of these costs. APS cannot continue to offer superior electric service and invest in the programs and projects that promote Arizona's energy policy without the rate relief requested in this Application.

V. CONCLUSION.

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. In the 2009 Settlement Agreement, APS came together with the Commission and many other parties to discuss Arizona's energy future. Participants included representatives of environmental organizations, business associations, community groups and other interested stakeholders. The result was a long-term energy plan that includes ambitious goals for renewable energy and energy efficiency, and funds continued investments in reliability. Today, APS is achieving those goals. Our service reliability and customer satisfaction rank in the top-performing quartile of our industry, and we are diligently managing our costs.

With this Application, we are asking the Commission to continue its support for the goals set forth in the 2009 Agreement. We are also asking the Commission to modernize our rate structure to reflect the importance of energy efficiency as a clean and cost-effective component of Arizona's resource portfolio and, when future electricity rate increases become necessary, to make them more predictable and gradual for customers.

The plan reflected in this Application is good for APS customers and good for Arizona. We are committed to providing our customers with electricity that is safe, reliable, efficient and environmentally responsible. We believe the Commission shares these objectives and we urge the Commission to approve the requests made in this Application.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Jeff B. Guldner

DIRECT TESTIMONY OF JEFFREY B. GULDNER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-_____

June 1, 2011

Table of Contents

I. INTRODUCTION 1
II. SUMMARY 2
III. CONTINUING THE REGULATORY AND FINANCIAL MOMENTUM 4
IV. OVERVIEW OF THE COMPANY'S RATE CASE FILING 7
V. SETTLEMENT PERFORMANCE REQUIREMENTS 17
VI. CONCLUSION 20

Solar Post-Test Year Plant Additions Projects ..... Attachment JBG-1
Concentric Report ..... Attachment JBG-2

DIRECT TESTIMONY OF JEFFREY B. GULDNER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-_____)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Jeffrey B. Guldner. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004. I am Vice President of Rates and Regulation for APS. In that role, I am responsible for rate, regulatory and regulatory compliance matters before the Arizona Corporation Commission ("Commission") and the Federal Energy Regulatory Commission ("FERC") that affect the Company.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I joined APS in 2004 as Director of Regulatory Compliance, and then assumed responsibility for federal regulation and policy at the Company. Prior to joining APS, I was a partner in the Phoenix, Arizona office of Snell & Wilmer LLP, where I practiced energy and public utilities law. My practice focused primarily on electric utility rate and regulatory matters, including rate cases, power plant and transmission line siting, energy project finance, and utility mergers. Before practicing law, I was a Surface Warfare Officer in the United States Navy. I received a J.D., *magna cum laude*, from Arizona State University and a B.A. in political science from the University of Iowa.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. I discuss several of the many benefits that resulted from the 2009 Settlement Agreement ("Settlement"), which was approved by the Commission in Decision No. 71448 (December 30, 2009), and the critical need to maintain in this proceeding the financial and regulatory momentum established by the Settlement. I then outline the scope of APS's rate request and describe the key issues in that request. Finally, I touch on some of the performance measures as set forth in

Section XIII of the Settlement, including the Reporting Requirements and the Benchmarking Study.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Settlement marked a turning point in the challenging task of providing for the electric infrastructure needed for Arizona's future, while allowing APS the financial strength and stability to attract the capital required to build or acquire that infrastructure. It did so by providing for both significant cash rate relief and creative non-cash mechanisms that allowed APS to bridge the period from January 1, 2010 to the anticipated effective date of rates from this proceeding. That Settlement was favorably received by the financial community, as were subsequent constructive actions by this Commission. This rate request furthers this positive momentum and would allow the Company, the Commission and customers to continue taking important steps towards a sustainable energy future for Arizona.

The present request asks for an increase in base rates of $95.5 million, or 3.3%, to become effective July 1, 2012. Because the current negative Power Supply Adjustment ("PSA") charges would be reset to zero concurrently with the change in base rates, the actual percentage impact of the Company's request on APS customer bills will be higher, at approximately 6.6%. As discussed later in my Testimony, APS has sought to moderate the level of bill impact on customers by not seeking recovery of certain costs in this proceeding that APS believes are legitimate costs of providing service, including amounts that the Company had been granted in prior cases.

Although I will go into additional detail as to the principal drivers of the Company's rate request later in my Direct Testimony, it is fair to say that the three main issues in APS's rate Application are (1) inclusion by the Company in its Fair Value Rate Base of net plant additions through the proposed rate effective date; (2) expansion of the current Environmental Improvement Surcharge ("EIS") to an Environmental and Reliability Account ("ERA") that would encompass new generation additions and additional pollution control costs on existing generation on an annual basis; and (3) adoption of a rate decoupling plan, consistent with the Commission's 2010 Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures ("Decoupling Policy Statement"), through an Efficiency and Infrastructure Account ("EIA").

APS has achieved all the performance metrics and requirements of the Settlement that were targeted for 2010. For those that require performance over a period of time that encompasses future years, the Company is on track to meet them. Specifically, my testimony (as well as that of other APS witnesses) will discuss nine performance measures required by Section XIII of the Settlement:

- Expense reduction
- Equity infusion
- Debt ratio
- Financial plan to maintain investment grade ratings
- Renewable energy
- Energy efficiency
- Other reporting requirements
- Benchmarking study

III. CONTINUING THE REGULATORY AND FINANCIAL MOMENTUM

Q. DID THE SETTLEMENT GENERATE SIGNIFICANT REGULATORY AND FINANCIAL MOMENTUM FOR APS AND THE STATE OF ARIZONA?

A. Absolutely. I will not repeat the quotes from Jim Hatfield's testimony, but there can be no question that the financial community viewed the Settlement and the Commission's approval thereof as constructive for APS, APS's relationship with the Commission, and the investment climate in Arizona.

Q. WHY IS THAT THE CASE?

A. There is an inherent tension between the need for APS to invest for a sustainable and reliable energy future in Arizona and the natural desire to keep electric rates as low as possible. The Company's financial condition has historically suffered in this "tug of war" between two often conflicting goals. The Settlement not only came up with creative ways of mediating that tension, it also established a regulatory framework for addressing this challenge in future APS rate proceedings.

Q. CAN YOU BE MORE SPECIFIC?

A. Certainly. The Settlement's inclusion of post-test period investment up until roughly the date of the Settlement significantly reduced regulatory lag for APS and, importantly, reduced the requested rate increase in this case by about $88 million. The deferrals of pension and Other Post Retirement Benefits ("OPEB") costs that exceeded the level reflected in the Settlement's revenue requirement, the early change in Palo Verde depreciation rates resulting from the license extension granted by the Nuclear Regulatory Commission, and the reclassification of Schedule 3 (line extension) proceeds as operating revenues rather than contributions all represented important accounting changes that allowed APS to agree to both a lower base rate increase in the Settlement and a 30 month moratorium before the Company could receive any additional base rate relief. Although still well below the authorized equity return, these Settlement

provisions coupled with aggressive cost management allowed APS's earned equity return in 2010 to get closer to its authorized return.

The Settlement also allowed concurrent recovery of capital carrying costs for APS-owned renewable generation, which formed the basis for the AZ Sun Program ("AZ Sun") and the Community Power Project - Flagstaff Program ("CPP") approved by this Commission in Decision Nos. 71502 (March 17, 2010) and 71646 (April 14, 2010). Those Decisions were also favorably received in the investment community. And, although not nearly as significant in terms of potential financial impact as either of the rulings involving renewable energy, the Commission's more recent determination in Decision No. 72214 (March 3, 2011) to allow some capital carrying costs to be recovered through the Demand Side Management Adjustment Clause ("DSMAC") was also another sign that APS investments in service to customers were receiving more timely recovery than had historically been the case.

The Settlement looked to future APS rate proceedings as well. For this Application, the Settlement established a goal of a 12-month resolution of the APS rate filing (from a finding of sufficiency) and set in place procedural innovations to facilitate achievement of that goal, including the 120-day pre-notification, the 60-day pre-filing conference with Staff and other interested parties, and the submission of responses to a standard set of data requests concurrent with the Application.

Q. HOW DOES THE CURRENT RATE FILING ATTEMPT TO CONTINUE THAT REGULATORY AND FINANCIAL MOMENTUM?

A. I believe everyone agrees on the benefits to APS customers, the Commission, and APS itself of less frequent general rate cases. The resources and attentions of all three can be redirected toward other worthwhile objectives. I also believe strongly in rate gradualism. In a national environment of increasing costs, and

therefore rates, smaller increases on a regular and more predictable basis are better for customers than large double-digit jumps every few years. They are also more effective in financing the needed investment in new, efficient and cleaner infrastructure and innovative technology. Thus, APS customers find themselves in a better position to manage and predict future bill impacts, while APS is similarly in a stronger financial position to attract the approximately $20 billion in new capital investments that customers will require between now and 2025.

The key to achieving both less frequent general rate cases and rate gradualism is to find mechanisms, as was done in the Settlement, which will maintain the Company's financial strength between general rate filings. I believe we have accomplished this with the rate proposals discussed in the testimony filed by the Company, including my own. In addition, APS has structured its rate case testimony to be primarily about what APS is doing and needs to do in the future to procure and deliver energy and related services to its customers, and less about numbers, accounting classifications, and ratings agencies. In other words, what are APS customers receiving for their money both now and in the future? I believe that the testimony will show that APS customers are and will be receiving good value in terms of cost management, reliability, customer service, and sustainability – both environmentally and economically.

Q. ARE THERE OTHER ITEMS IN THE FILING THAT APS IS NOT INCLUDING OR FOR WHICH IT IS SEEKING A REDUCED AMOUNT?

A. Yes. APS is aware of the difficulties our customers face in the current economic climate. Accordingly, APS carefully looked for opportunities to moderate the bill impact of this request to customers. Based on this consideration, APS is not requesting recovery of stock compensation or Supplemental Executive Retirement Benefits Plan ("SERP") costs in this case. These components to compensation are standard costs incurred by utilities throughout the United

States, and accordingly APS believes that they normally should be included in APS's cost of service. But in the context of this rate case, brought at a time when our customers are still trying to recover from a weak economy, APS concluded that it would not seek to include these costs in its rate request. For the same reason, APS decided to reduce the Fair Value increment it would request in this rate case below that supported by its expert, APS witness Dr. William Avera, and below even the level that was recommended by Commission Staff and incorporated in the 2009 Settlement Agreement. Dr. Avera explains in his testimony why a higher Fair Value increment is the most appropriate measure of Fair Value for APS. APS also chose to maintain the 11.0% return on equity ("ROE") authorized by the Settlement, rather than request the 11.25% Dr. Avera identifies as the mid-point of his range. APS was able to propose a lower Fair Value increment and authorized ROE because of the balance of other aspects of the case, such as inclusion of post-Test Year plant and the other proposed mechanisms—without those, APS would have to seek the higher Fair Value increment and ROE. Both of these steps, as well as the decision to not seek recovery of stock compensation and SERP, helped to moderate the requested rate increase below a 7.0% bill impact for customers and lowered the revenue requirement increase by over $50 million. This is in addition to over $37M in expense reductions achieved during the Test Year, which I will discuss later in my testimony.

IV. OVERVIEW OF THE COMPANY'S RATE CASE FILING

Q. WHAT LEVEL OF BASE RATE INCREASE IS APS REQUESTING?

A. APS is seeking a base rate increase over adjusted Test Year base rate revenues of $95.5 million, to become effective July 1, 2012. This represents a 3.3% increase in base rate revenues. To be clear, however, the base rate increase is different from the bill impact to customers because of corresponding changes in several

adjustment mechanisms. For example, under the Company's proposal to reset the base fuel rate to reflect conditions and prices expected in 2012, the present PSA forward element adjustment is moved from an adjustment mechanism into base rates. Because that PSA forward element for both this year and 2012 is negative, the mathematical impact is to reduce the size of the proposed base rate increase shown on SFR Schedule A-1 without reducing the bill impact of APS's request on most customers. It is important, therefore, to also discuss the net bill impact, because that is what customers ultimately will care about. Considering surcharges such as those for energy efficiency, renewable energy, transmission, and environmental improvements along with adjusted base rate revenues, the overall bill impact of the Company's request would be an increase of 6.6%.

Q. SOME APS CUSTOMERS HAVE EXPRESSED CONCERN THAT THIS RATE CASE REPRESENTS ANOTHER IN A LONG SERIES OF SIGNIFICANT RATE INCREASE REQUESTS BY THE COMPANY. IS THAT FACTUALLY CORRECT?

A. While APS recognizes our customers' natural concerns over higher prices, the fact is that for the three and one-half years between January 1, 2009 and the proposed effective date for new rates in this proceeding, there will have been only one general rate case resulting in an increase for APS customers. There have been other rate changes in this period to date, including four related to Renewable Energy and Energy Efficiency programs that are overwhelmingly supported by APS customers. But I believe that customers perceive that there have been many more rate changes because they receive notices about the same rate change several times during a rate case process, and APS's approved adjustor mechanisms are implemented at different times during each calendar year.

Q. WHAT HAS BEEN THE OVERALL TREND IN RATES PAID BY APS CUSTOMERS SINCE 2009?

A. In January 2009, the average cost paid by APS customers was 10.2 cents per kWh. Today, the average rate is 10.6 cents per kWh. This is an increase of approximately 4% over two and one-half years. Renewable Energy and Energy Efficiency programs account for 3.4 percentage points of that 4%. Further, the base rate increase sought by APS in this case will not be implemented before July 1, 2012—more than 12 months from the filing of my testimony.

Q. WHAT WITNESSES IS APS PRESENTING AS PART OF ITS DIRECT CASE?

A. APS filed testimony from the following witnesses:

Mr. Donald G. Robinson	State of the Company and general content of rate case
Mr. Jeffrey B. Guldner	Overview of the rate case and central issues
Mr. James R. Hatfield	Financial projections and bond rating information
Mr. Mark A. Schiavoni	Fossil generation operations and capital expenditures
Mr. Randy K. Edington	Nuclear generation operations and capital expenditures
Mr. Daniel T. Froetscher	Distribution operations and capital expenditures
Dr. William E. Avera	Cost of equity and fair value rate of return
Mr. Leland R. Snook	Efficiency and Infrastructure Account and the Environmental and Reliability Account
Mr. Zachary J. Fryer	Cost of service and fair value calculation
Mr. Jason C. La Benz	Historical accounting information and rate base and income statement pro formas
Dr. Ronald E. White	Depreciation study and cost expense

Mr. Peter M. Ewen	Base fuel cost and the Power Supply Adjustor
Mr. Charles A. Miessner	Rate design and programs

Q. WHAT ARE THE CENTRAL FACTORS NECESSITATING THIS BASE RATE INCREASE?

A. By far the largest driver is the over $1.5 billion increase in APS investment between the time Settlement rates went into effect through the anticipated effective date of rates in this proceeding. This amount represents investments in reliability, power plant efficiency, environmental equipment, renewable energy and new technology. These investments made since the last rate case require new rates so that APS can earn closer to its cost of equity capital. There have also been some operating cost increases, but APS has essentially offset those increases through cost reductions elsewhere.

Q. IN YOUR SUMMARY, YOU IDENTIFIED POST-TEST YEAR INVESTMENT, THE PROPOSED ENVIRONMENTAL AND RELIABILITY ACCOUNT AND THE EFFICIENCY AND INFRASTRUCTURE ACCOUNT AS THREE MAJOR ISSUES IN THIS CASE. WILL YOU PLEASE DISCUSS EACH OF THESE PROPOSALS?

A. Certainly. First, the goal of the post-Test Year plant adjustment is to reflect the net plant additions that have actually been placed into service by the rate effective date, as well as some associated operating costs. "Net" plant additions recognize the increase in the depreciation reserve, changes in deferred income taxes, and (where applicable) investment tax credits as offsets to gross plant additions. In other words, these offsets lower the total amount of post-Test Year plant requested. Mr. La Benz will explain the details of these offsets in his testimony. Similarly, the heads of the business units responsible for energy delivery including general and intangible plant (Daniel Froetscher), fossil generation (Mark Schiavoni) and nuclear generation (Randy Edington) will discuss the plant additions within their respective areas in greater detail. As in the Settlement, the

post-Test Year plant adjustment will be updated to reflect actual plant additions closed to service by the effective date of new rates.

I will address post-Test Year plant associated with the Solar Additions portion of the post-Test Year plant additions pro forma. The adjustment includes post-Test Year plant additions associated with three of APS's renewable energy programs: AZ Sun, the Schools and Government Program ("S&G Program"), and the CPP. Each of APS's renewable energy programs included in the post-Test Year plant additions adjustment was previously approved by the Commission. Costs for these programs are currently recovered through APS's Renewable Energy Surcharge ("RES"). As explained by Mr. Miessner, APS plans to concurrently reduce its RES rates on the effective date of new base rates to reflect the transfer of these costs out of the RES and into base rates.

As noted earlier, AZ Sun was approved by the Commission in Decision No. 71502. Through this program, APS will own 100 MW of utility-scale solar photovoltaic power plants across Arizona, investing up to $500 million through 2014. APS uses competitive procurement processes to select projects under AZ Sun. As discussed by Mr. Robinson, APS has signed contracts to develop five generating facilities representing the first 83 MW of the 100 MW program. This post-Test Year plant additions adjustment includes three AZ Sun projects, totaling 50 MW, that are projected to be in service by June 30, 2012: a) Paloma, a 17 MW facility located in Gila Bend with a projected in-service date of September 2011; b) Cotton Center, a 17 MW facility also located in Gila Bend with a projected in-service date of November 2011; and c) Hyder, a 16 MW facility located east of Yuma with a projected in-service date of October 2011 for the first phase and March 2012 for the second phase of the facility. As provided in Decision No. 71502, the first 50 MW of AZ Sun will be recovered through the

RES until the investment is included in base rates or another recovery mechanism as determined in the Company's next rate case. APS recommends that after existing AZ Sun revenue requirements are moved from the RES into base rates in this case, the recovery of remaining costs associated with the second 50 MW occur through the RES until they can be incorporated in base rates by a future APS rate case rather than through a new adjustment mechanism.

The S&G Program was approved by the Commission, as amended, in Decision No. 72174 (February 11, 2011). As part of this program, rural and economically challenged school districts are provided with access to solar resources owned and operated by APS. As host for the APS-owned system, the school receives the benefits of solar produced by the system through a twenty-year fixed Solar Rate offering. Full deployment of 8 MW of APS-owned systems is expected to be complete by June 30, 2012.

The CPP was approved by the ACC in Decision No. 71646 (April 14, 2010), and through this program, APS will install and own up to 1.5 MW of distributed renewable energy systems in Flagstaff, AZ. Full deployment is expected to be complete by December 2011.

The renewable energy programs, including AZ Sun, the S&G Program and the CPP, which are included in the total post-Test Year numbers discussed above, increase Rate Base by $267,633,000 and decrease pre-tax operating income by $12,385,000. Please see Attachment JBG-1 for a calculation of this rate base adjustment.

Q. PLEASE EXPLAIN THE ENVIRONMENTAL AND RELIABILITY ACCOUNT ("ERA").

A. The second major issue is the Company's proposed ERA, which would replace the existing EIS. The account would include net investments in pollution control

equipment at the Company's power plants as well as investments in new non-renewable generation. The Company would propose continuing to recover the carrying costs and operating costs of Company-owned renewable generation through the RES until such time as such generation can be rolled into base rates during future APS general rate proceedings. The ERA allows rates to reflect the cost of investments in environmental equipment that are largely outside the control of either APS or the Commission. The details of the ERA are discussed in Mr. Snook's testimony.

It is important to note that the ERA would not divest this Commission of its power and responsibility to determine the prudence of new investments subject to the ERA. Prudence determinations would continue to be made in general rate proceedings or in other proceedings as the Commission determines are appropriate from time to time.

Q. EXPLAIN THE EFFICIENCY AND INFRASTRUCTURE ACCOUNT ("EIA").

A. Under the EIA, the Commission establishes a dollar amount of fixed costs for the adjusted test period (which in this case is historical, though it need not be) and divides it by the number of customers for that same adjusted test period. APS's goal is to make the mechanism as simple as possible while still being an accurate reflection of fixed cost per customer. Although Mr. Snook is discussing the EIA proposal in detail, I can say that we determined the fixed cost calculation using (with some minor exceptions) two broad groups of retail customers – all residential and all general service and industrial.

The total level of fixed costs to be recovered will vary from year to year depending on customer count. APS has further proposed an annual cap of 3% for any upward rate adjustment due to the EIA with a carryover to the succeeding

year. There would be no similar cap on downward adjustments, which would result in bill credits to customers.

Q. WHY IS APS MAKING THIS PROPOSAL NOW?

A. During the decoupling workshops conducted in the summer and fall of 2010, it was generally acknowledged by all participants expressing an opinion that the Commission's energy efficiency standard could not be met unless there was an alignment of interests between the Company and its customers. This conclusion is shared by numerous other state commissions and policy experts throughout the United States. This state's aggressive commitment to distributed generation is yet another reason that finding a way for APS to recover fixed costs in the face of declining sales per customer is imperative.

In recognition of these facts, the Commission issued a comprehensive Decoupling Policy Statement in December of 2010. In his testimony, Mr. Snook describes how the APS proposal matches up against the Decoupling Policy Statement and explains what minor deviations from that statement are included in the Company's filing.

Q. COULD YOU OUTLINE SOME OF THE OTHER SIGNIFICANT COMPONENTS OF THE COMPANY'S RATE REQUEST?

A. Yes. Although there are many aspects to this rate request (as there are for other major utilities in this state), I will elaborate here on the following:

- Changes to the Transmission Cost Adjustment ("TCA");
- Changes to the PSA;
- The Company's requested ROE; and
- Implementation of a revised line extension policy in the form of Revision 12 to Service Schedule 3.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE TCA.

A. There are two. First, all transmission costs associated with serving retail customers would be recovered through the TCA rather than through a combination of base rates and the TCA. Second, changes to the TCA would take effect at the same time as new transmission rates become effective for wholesale customers of APS – June 1st of each year – without the need for a separate approval from the Commission.

The second modification of the TCA is related to the first. By federal law, FERC has exclusive jurisdiction over APS's transmission rates to both retail and wholesale customers. Retail customers are protected through this Commission's active participation in FERC formula rate proceedings – something it has done successfully in each of the past three years. It makes little sense for the Commission to simply reflect in a separate order a decision already made by another agency. And by putting all retail transmission costs into the TCA, APS customers can see the full impact of FERC decisions on their bills.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE PSA.

A. Again, there are two significant changes to the PSA proposed in APS's filing. The first is to include chemical costs such as lime, ammonia, and sulfur in the costs recoverable through the PSA. Use of these environmental chemicals is directly related to generation output every bit as much as is fuel and should be treated accordingly for ratemaking purposes. Second, the Company seeks to remove the 90/10 "sharing" provision from the PSA. Although APS is currently benefiting from that sharing, this does not change the fact that no other Arizona utility has such a provision. Given the volatility of fuel prices, it is little more than an arbitrary penalty or, currently, benefit to the Company for something over which it has virtually no control. On the other hand, if fuel charges to APS customers are the result of imprudent acts of APS, the Commission has complete

authority to order such increased costs refunded or credited to customers as it did in Decision No. 69663 (June 28, 2007).

Q. WHAT COST OF COMMON EQUITY DID APS USE IN ITS RATE REQUEST?

A. Considering the cost of equity capital recommendation made by Dr. Avera and consistent with the findings in the Settlement, APS based its request on an 11% ROE. As discussed earlier, this request is lower than the midpoint of Dr. Avera's recommendation.

Q. WHAT CHANGES ARE PROPOSED FOR SCHEDULE 3?

A. Generally speaking, we are suggesting that the Company return to the traditional accounting treatments of line extension proceeds, which are either refundable advances or non-refundable contributions. Revenue treatment was a creative and necessary bridge in the Settlement, but its long-term instability as a revenue source has convinced the Company that a return to more conventional accounting should be made at this time.

As to the structure of Schedule 3, the Company wants to promote a sharing of the costs of new customer growth between the new customers and the existing customer base. I believe we have found a good balance between the somewhat divergent interests of these two customer groups.

Q. ISN'T THERE A SEPARATE PROCEEDING UNDERWAY TO RE-EXAMINE SCHEDULE 3?

A. Yes. On May 20, 2011, APS filed a revised Schedule 3 (Version 12) that reflected consensus with several affected parties. The intent of the Company and the other parties to that agreement is to implement this revised line extension policy concurrent with the effective date of new base rates as determined in this proceeding. However, creating more immediate certainty around the prospective line extension policy and receiving Commission approval to extend the refund

period of customer advances under previous revisions to Schedule 3 led APS to file for separate approval.

V. SETTLEMENT PERFORMANCE REQUIREMENTS

Q. HOW IS APS DOING WITH REGARD TO THE PERFORMANCE STANDARDS ESTABLISHED IN THE SETTLEMENT?

A. I will comment on these in the order listed in my Summary.

- Expense Reduction: On April 29, 2011, APS filed a letter detailing its compliance with the requirement that it achieve $30 million in expense savings in 2010. As can be seen by the letter, the Company actually achieved $37.4 million in expense reductions. This means that the current request was reduced by these and other cost reductions that did not meet the definition of expense reductions (largely reductions in capital investment).

- Equity Infusion: The Company received the first installment ($253 million) of this equity infusion in April of 2010 following a successful equity issuance by Pinnacle West Capital Corporation, the parent of APS. Future installments will get APS to the $700 million by 2014 referenced in the Settlement.

- Debt Ratio: APS is required to use "best efforts" to achieve a 52% long-term debt ratio as determined using Standard & Poor's ("S&P") calculation methodology by the end of 2012. At year-end 2010, APS had reduced its debt ratio using that methodology to 54.4% from 56.6% at year-end 2009. APS currently expects to reach 52% or less by the end of 2012.

- Financial Plan to Maintain Investment Grade Credit Ratings: On April 29, 2010, APS submitted such a Plan to the Commission. Mr. Hatfield addresses the details of the Plan, but generally it consists of seeking timely recovery of costs in rates, on-going cost management activities, and maintaining a balanced capital structure.

- Renewable Energy: APS made a number of commitments relative to renewable energy in Section XV of the Settlement. These included: (1) new resources capable of generating 1.7 million MWh by the end of 2015, (2) a "schools" program eliminating "up front" costs of solar, (3) a government institutions program with the same objective as the "schools" program, (4) an Arizona wind project, (5) a utility scale photovoltaic project, and (6) a renewable-related transmission project. As to items 2-6, I will not go into detail except to note that APS proposed and the Commission approved each of these required projects. As to item 1, APS acquired renewable resources in 2010 capable of providing 172,734 MWh out of a total renewable resource generation production of 826,534 MWh. The Company presently anticipates that total production will grow to over 3 million MWh by 2015 – exceeding the requirements of the Settlement.

- Energy Efficiency: Section XIV of the Settlement required APS to achieve 1% savings as measured by total energy resources. This is a somewhat higher requirement than in the Commission's Energy Efficiency Rules. In fact, the Company and our customers achieved 1.05% energy savings during 2010. The Commission approved the Company's 2011 DSM Implementation Plan (with minor modifications), which is aimed at the 1.25% goal for 2011. Both the 2011 and now the 2012 Implementation

Plans were filed as required by the Settlement and the Rules on June 1, 2010 and June 1, 2011, respectively.

- Other Reporting Requirements: Section XIII (B) of the Settlement set forth extensive reporting requirements relating to system operations, customer service, safety, and financial results. I will not repeat them all here, but suffice it to say all required reports were submitted to the Commission in a timely fashion.

- Benchmarking Study: The Company appreciates the effort and analysis presented by Liberty Consulting ("Liberty") in Liberty's report filed on February 28, 2011. APS is in partial agreement with Liberty's findings. Where we are not in agreement, or where the recommendation was for APS to more closely evaluate a potential finding in Liberty's higher level analysis, an APS witness will address certain issues, while a report prepared by the Company's independent benchmarking consultant, Concentric Energy Advisors ("Concentric") addresses others. APS believes that benchmarking, such as the process agreed to in the Settlement, is a worthwhile undertaking, and the Liberty and Concentric benchmarking analyses provide significant information for discussion and consideration in a rate case context.

Q. WHAT ANALYSES DID CONCENTRIC UNDERTAKE?

A. We asked Concentric to do several things. First, we asked them to review the Benchmarking Study performed by Liberty, and discuss the overall goals and objectives of a benchmarking process in somewhat more detail than Liberty had included in its report. Second, for areas where Liberty had identified the need for further analysis or action by the Company, we asked Concentric to conduct that further analysis and discuss their findings. Finally, the scope of the Liberty study

only included data through 2009. We asked Concentric to update the benchmarking to also include 2010. In some areas evaluated by Liberty, the trend after 2009 appeared necessary to interpret their findings. The complete Concentric report is attached to my testimony as Attachment JBG-2.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. As I noted in my Summary, the Settlement addressed in a very constructive manner the challenge of providing for the electric infrastructure needed for Arizona's future while allowing APS the financial strength and stability to attract the capital required to build or acquire that infrastructure. The Settlement was a major milestone for the settling parties and the Commission and has earned every word of the praise it has received.

The present request seeks to build on the constructive momentum of that Settlement by proposing means to reduce the frequency and magnitude of general rate cases while allowing for improved cost recovery and reduced regulatory lag. It also will align the financial interests of the Company with those of its customers to better promote energy efficiency, renewable energy, and environmental stewardship. Finally, APS has achieved all the performance metrics and requirements that were targeted for 2010 by the Settlement and is on track to achieve those that can only be finalized in future years.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustment to Original Cost Rate Base for Solar Generation Post-Test Year Plant Additions
as Shown on Schedule B-2, page 1, column 3
Total Company
(Thousands of Dollars)

Pro forma Adjustment: **Post-Test Year Plant Additions**
Adjustment to Test Year rate base to include Post-Test Year Plant Additions for solar generation with an estimated in-service date prior to 6/30/2012.

Line No.	Description	Total Company
1.	Gross Utility Plant in Service	$ 277,411
2.	Less: Accumulated Depreciation and Amortization	5,799
3.	Net Utility Plant in Service	271,612
4.	Less: Total Deductions	3,979
5.	Total Additions	-
6.	**Total Rate Base**	**$ 267,633**

ARIZONA PUBLIC SERVICE COMPANY

REVIEW OF LIBERTY BENCHMARKING STUDY AND SUPPLEMENTAL ANALYSES

Prepared by:

CONCENTRIC

293 Boston Post Road West, Suite 500
Marlborough, MA 01752
508.263.6200 • 508.303.3290 *fax*
www.ceadvisors.com

JUNE 1, 2011

TABLE OF CONTENTS

I. Executive Summary 1

A. Purpose of the Assignment 1

B. Conclusions 1

II. Review of The Liberty Study 3

A. Background 3

B. Study Approach 4

i. Panel Design 4

ii. Definition of Expectations 8

iii. Data Acquisition 8

iv. Data Analysis 9

v. Presentation of Recommendations 9

C. Study Findings and Recommendations 9

i. Areas of Average/Above Average Performance 9

ii. Areas of Below Average Performance 12

D. Concentric Review 15

i. Panel Design 15

ii. Databases and Screens Used for Plant Performance 16

iii. Use of Performance Expectations 16

iv. Study Findings 17

III. Concentric Updated 2010 Benchmarking Study 24

A. Introduction and Approach 24

i. Panel Selections 24

v. Selection of Metrics 25

vi. Data Analysis 25

B. Situational Assessment 26

C. Productive Efficiency Assessment 29

D. Service Quality Assessment 34

IV. Conclusions 35

Exhibit 1: Situational Assessment

Exhibit 2: Productive Efficiency

Exhibit 3: Benchmarking Workpapers

Attachment A: Matrix of Metrics and Panels

Attachment B: Nuclear O&M Expenses

Attachment C: Underground Distribution Systems

Attachment D: Labor Efficiency Metrics

Attachment E: Nuclear Plant Metrics

Attachment F: Fossil Plant Metrics

Attachment G: Distribution System Reliability Metrics

I. EXECUTIVE SUMMARY

A. PURPOSE OF THE ASSIGNMENT

Arizona Public Service Company ("APS") retained Concentric Energy Advisors, Inc. ("Concentric") to conduct an independent review of the benchmarking study prepared by Liberty Consulting Group ("Liberty") and commissioned by the Arizona Corporation Commission ("ACC" or "Commission") in Docket No. E-01345A-08-0172 (the "Liberty Study"). Our review included both an examination of the approaches and methods used by Liberty in measuring APS's performance, as well as an assessment of the recommendations made by Liberty for improvements in certain areas.

In addition to reviewing the Liberty Study, we also prepared an updated benchmarking study using operating data and costs through 2010 (the "Concentric Study"). The Concentric Study used our typical approach and method to benchmarking the performance of investor-owned utilities. In addition, we developed an analysis showing the areas in which the Concentric Study differed from the Liberty Study in terms of approach, analysis and results and reviewed the reasons for these differences.

B. CONCLUSIONS

Based on our analysis, Concentric concludes the following:

- We generally found Liberty's approach to the APS benchmarking study to be reasonable and consistent with industry practice. However, we had a number of specific concerns with its comparison panels, presentation of results, and recommendations. We address each of these concerns in our review of its study.

- Our review of APS's performance has demonstrated that the Company has out-performed similarly sized companies across an array of financial and operational metrics. The Company has achieved this result in spite of the fact that it is somewhat disadvantaged by the exogenous factors that are known to have an impact on efficiency. APS is consistently one of the three most "situationally-challenged" companies within the comparison groups. APS's customer base consists of a high percentage of residential customers with low usage, its growth has been high, and its service territory is more rural than its peers. In addition, the state's energy policies will likely place future cost pressures on APS to continue to increase participation in demand-side management and energy efficiency programs, meet renewable energy portfolio requirements, and reduce air emissions from its generation fleet.

- In terms of productive efficiency, APS has ranked in the second and third quartile in ten out of eleven years in the Base Panel and ranks between the first and third quartile

in the Regional Panel in terms of productive efficiency over the course of the study period. Most importantly, APS's performance on the productive efficiency benchmark has not occurred at the expense of service reliability or customer satisfaction.

- Considering both the challenges identified in the situational assessment and the productive efficiency, APS's performance in 2010 was exceptionally good, and APS outperformed its Base Panel peers on a basis which considers both absolute productivity measures and the relative challenges it faced.

The remainder of this report is organized into the following sections:

- Section II provides a review of the Liberty Study, including i) the study approach; ii) the study findings and recommendations; and (iii) Concentric's assessment of the Liberty Study.
- Section III presents the Concentric Study. This section includes a review of: (i) the development of peer group panels; (ii) the data sources used; (iii) the exogenous factors that present performance-related and cost-related challenges to APS; (iv) productive efficiency metrics and performance metrics and a ranking of APS in each of these areas; and (v) an analysis of the differences between the Liberty Study and Concentric Study.
- Section IV summarizes our conclusions based on our updated study.

II. REVIEW OF THE LIBERTY STUDY

A. BACKGROUND

The ACC commissioned Liberty to conduct a benchmarking analysis of certain attributes of APS. The need for the study emerged from a rate proceeding under Docket No. E-01345A-08-0172, and a settlement reached among the parties defined the nature and scope of the analysis. Specifically, the settlement agreement required that the ACC select a firm to conduct a benchmarking analysis of APS's operational and cost performance relative to a peer group of at least 30 other investor-owned electric-only utility operating companies. The settlement agreement required that the study focus, at a minimum, on the following areas:

- Operational performance
  - ✓ Safety
  - ✓ Customer Satisfaction
  - ✓ Delivery reliability
  - ✓ Base load power plant performance
  - ✓ Sustainability performance
- Cost performance
  - ✓ Non-fuel operating expense per customer
  - ✓ Distribution additions to plant per new customer
  - ✓ Capital expenditures
  - ✓ Hedging
  - ✓ Management of Expense
- Financial Health
  - ✓ Debt/equity ratio
  - ✓ Dividend payout ratio
  - ✓ Return on average assets
  - ✓ Return on average equity
  - ✓ FFO/Debt
  - ✓ Debt Ratings
  - ✓ Earnings per share (PNW) Stock Performance (PNW)

APS was required to pay for all costs for the benchmarking study up to $500,000 and was not allowed to recover the costs in rates.

The ACC issued a request for proposals ("RFP") to conduct the benchmarking analysis of APS pursuant to the settlement agreement, and awarded the contract to Liberty on March 31, 2010. The Liberty Study was filed with the Commission on February 28, 2011.

B. STUDY APPROACH

The process used by Liberty to conduct the benchmarking analysis included five basic elements: (i) panel design; (ii) definition of expectations; (iii) data acquisition; (iv) data analysis; and (v) presentation of recommendations. Each of these steps is discussed in further detail below.

i. Panel Design

The study process began with Liberty selecting multiple peer groups, or panels, against which to measure APS's performance. The settlement agreement, and the RFP, specified certain requirements for peer groups. Where practical, peer groups were required to meet the following criteria:

- At least 30 other investor-owned electric-only utility operating companies;
- Comparable revenue, customers, ownership of nuclear generation, customer density, growth and fuel and resource mix as APS;
- Include Salt River Project;
- A 10 year running period; and
- Segregation of data where possible between metropolitan and rural areas.

Liberty began with a base panel designed to fulfill the literal requirements of the RFP. The formation of the base panel initially included 128 regulated energy companies corresponding to Federal Energy Regulatory Commission ("FERC") Form 1 data. This comprehensive list of companies was then filtered using the following criteria:

- More than 300,000 electric customers; and
- Ownership of regulated generation.

The resulting final base panel included 40 regulated electric utilities,[1] including APS, as shown in Table 1.[2]

[1] Please note, while some companies have "Gas" in its name, they no longer have gas operations.

[2] Salt River Project was added pursuant to the requirements contained in the RFP and settlement agreement. However, Salt River Project ceased filing a FERC Form 1 in 2004.

TABLE 1: BASE PANEL

Base Panel	
Alabama Power Company	Kansas City Power & Light Company
Appalachian Power Company	Kansas Gas and Electric Company
Arizona Public Service Company	KCP&L Greater Missouri Operations
Carolina Power & Light Company	Kentucky Utilities Company
Columbus Southern Power Company	Monongahela Power Company
Dayton Power and Light Company	Nevada Power Company
Detroit Edison Company	Ohio Power Company
Duke Energy Carolinas, LLC	Oklahoma Gas and Electric Company
Duke Energy Indiana, Inc.	PacifiCorp
El Paso Electric Company	Portland General Electric Company
Entergy Arkansas, Inc.	Public Service Company of New Hampshire
Entergy Louisiana, LLC	Public Service Company of New Mexico
Entergy Mississippi, Inc.	Public Service Company of Oklahoma
Florida Power & Light Company	Salt River Project
Florida Power Corporation	Southern California Edison Co.
Georgia Power Company	Southwestern Electric Power Company
Gulf Power Company	Southwestern Public Service Company
Idaho Power Co.	Tucson Electric Power Company
Indiana Michigan Power Company	Virginia Electric and Power Company
Indianapolis Power & Light Company	Westar Energy (KPL)

While the RFP required electric only utilities, Liberty determined that in some cases, the electric/gas differentiation among the 128 regulated energy companies was irrelevant.[3] This resulted in an expanded base panel of 65 utilities, as shown in Figure 2 below.

[3] Liberty stated that this differentiation was irrelevant, but did not explain how they determined this irrelevance.

TABLE 2: EXPANDED BASE PANEL

Added Utilities in Expanded Base Panel	
Avista Corporation	Public Service Company of Colorado
Consolidated Edison Company of NY	Public Service Electric and Gas Company
Consumers Energy Company	Puget Sound Energy, Inc.
Duke Energy Ohio, Inc.	Rochester Gas and Electric Corp
Entergy Gulf States Louisiana, L.L.C.	San Diego Gas & Electric Co.
Interstate Power and Light Company	Sierra Pacific Power Company
Louisville Gas and Electric Company	South Carolina Electric & Gas Co.
MidAmerican Energy Company	Tampa Electric Company
New York State Electric & Gas Corp	Union Electric Company
Northern Indiana Public Service Co.	Wisconsin Electric Power Company
Northern States Power Company - MN	Wisconsin Power and Light Company
NorthWestern Energy Division	Wisconsin Public Service Corp
Pacific Gas and Electric Company	

In addition to the base and expanded panels, Liberty developed several tailored panels which recognized certain characteristics of APS and were used by Liberty to provide additional context to certain metrics and findings. These included a high growth panel, a regional panel, and a nuclear panel. The high growth panel was developed to analyze metrics that are typically affected by growth rates, and was defined as the 10 top growth companies in the base panel, with growth rates ranging from 2.4 percent to 4.5 percent, as shown in Table 3.

TABLE 3: HIGH GROWTH PANEL[4]

High Growth Panel	Annual Growth
Nevada Power Company	4.54%
Arizona Public Service Company	**4.22%**
Public Service Company of New Mexico	4.08%
Columbus Southern Power Company	3.72%
Salt River Project	3.64%
Florida Power & Light Company	2.79%
Tucson Electric Power Company	2.69%
Virginia Electric and Power Company	2.45%
Georgia Power Company	2.44%
Appalachian Power Company	2.44%
Gulf Power Company	*2.36%*
Gulf Power used when SRP unavailable	

[4] Note that growth was measured in terms of growth in MWh sales between 1999 and 2007.

Liberty created a regional panel to recognize similar locational characteristics. The nine companies included in the regional panel are shown in Table 4.

TABLE 4: REGIONAL PANEL

Regional Panel
Arizona Public Service Company
El Paso Electric Company
Nevada Power Company
PacifiCorp
Public Service Company of New Mexico
Salt River Project
Southern California Edison Co.
Southwestern Public Service Company
Tucson Electric Power Company

Liberty also created a nuclear panel to evaluate the costs associated with the ownership of nuclear generation. While a total of 18 companies in the Base Panel were found to have nuclear generation, as shown in Table 5, only eight fell within 50 percent of APS in terms of generation.

TABLE 5: NUCLEAR PANEL[5]

Nuclear Panel	
Alabama Power Company ☆	Florida Power Corporation ☆
Arizona Public Service Company	Georgia Power Company ☆
Carolina Power & Light Company	Indiana Michigan Power Company ☆
Detroit Edison Company ☆	Kansas City Power & Light Company
Duke Energy Carolinas, LLC	Kansas Gas and Electric Company
El Paso Electric Company ☆	Public Service Company of NM
Entergy Arkansas, Inc. ☆	Salt River Project
Entergy Louisiana, LLC ☆	Southern California Edison Co.
Florida Power & Light Company	Virginia Electric and Power Company

Note: ☆ indicates company within 50% of APS in terms of nuclear generation

In addition to the above base and tailored panels, Liberty developed several other generation-related panels which were used to evaluate the operational performance of APS's three coal-fired generating plants - Cholla, Four Corners, and Navajo; and one nuclear plant - Palo Verde. For the coal-fired units, Liberty developed two sets of panels using two databases and applied screens to these databases based on the general characteristics of the APS generating

[5] El Paso Electric Company, Salt River Project, Southern California Edison, and Public Service Company of NM are co-owners of the Palo Verde Station

units. The first database consisted of coal-fired plants operated by companies in the expanded base panel. Liberty then applied a capacity factor screen of greater than 60%. This group of units was then segregated into two panels: (i) large units with a capacity between 600MW and 1,000MW which totaled 68 units; and (ii) small units between 100 Megawatts ("MW") and 300MW which totaled 98 units. The second database consisted of all coal-fired units contained in the Generator Availability Data System ("GADS") sponsored by the North American Electric Reliability Corporation's ("NERC"). Liberty applied a size screen to this database and developed two panels: (i) large units with a capacity between 600MW and 1,000MW totaling 141 units; and (ii) small units with a capacity between 100MW and 300MW totaling 195 units.

Similar to the process used to develop the coal panels, Liberty developed the nuclear panels using two databases. The first database of nuclear plants included those plants operated by companies in the expanded base panel. This group of plants was then segregated into two panels: (i) those units with pressurized water reactors ("PWRs") which totaled 38 units; and (ii) those units with boiling water reactors ("BWRs"), which totaled 9 units. The second database consisted of all nuclear units contained in the NERC GADS. Liberty applied a size screen to this database and developed a panel of units with a capacity greater than 1,000MW totaling 51 units.

ii. Definition of Expectations

In addition to focusing on operational and financial parameters, Liberty supplemented its findings in each subject area based upon its expectations of where APS should fall relative to the peer group companies based upon its relative position in terms of specific key parameters. For example, APS might be the 4th largest in a panel, suggesting that APS should generally rank approximately 4th in terms of certain size-related performance measures (such as number of employees, total O&M costs, distribution investment, for example). Liberty used this approach to compare APS's actual performance in each functional area to Liberty's expectations.

iii. Data Acquisition

In terms of data acquisition and analysis, Liberty used various sources of publically available data, including the following sources:

- FERC Form 1;
- Occupational Safety and Health Administration ("OSHA");
- Edison Electric Institute ("EEI");
- NERC GADS; and
- Data provided by APS.

Liberty performed its analysis using this data to assess APS's performance in numerous areas, and attempted to supplement these findings with explanations and unique circumstances as provided through discussions with APS.

iv. Data Analysis

Liberty used the comparison panels and above sources of data to develop numerous operational and financial metrics to measure APS's performance against an applicable peer group. Specifically, Liberty gathered data in the areas of operational performance, cost performance and financial health from 2000-2009. Operational performance included an analysis of generating plant, distribution system, and customer service metrics. Cost performance included an analysis of the costs associated with the operation of APS's generating units as well as its transmission and distribution system, the hedging function and the management function in terms of number of employees and salaries and wages. These metrics were generally placed on a per unit output basis such as megawatt-hour ("MWh") sales or total customers. Finally, Liberty analyzed data related to APS's financial health such as returns and earnings. Once developed, all of the metrics in each of these functional areas were compared to the appropriate peer group over a specified time period. A list of metrics and the peer group used for each metric is shown in Attachment A.

In some cases, APS's metrics were averaged and shown against a peer group average over a ten year period. In other cases, APS's metrics were shown for each year against a peer group average.

v. Presentation of Recommendations

Based on its findings, Liberty provided several recommendations in each functional area that, in its opinion, warranted more analysis and focused follow-up.

C. STUDY FINDINGS AND RECOMMENDATIONS

i. Areas of Average/Above Average Performance

Based on a review of Liberty's approach and the findings and recommendations outlined in the report, APS was found to compare well against its peers in the areas shown below.

Cost and Performance:

- **Safety**

  Based on limited data from OSHA and EEI, APS's injury incident rate was below industry average from 2004 through 2009.

- **Customer Satisfaction**

Based on the 2010 J.D. Power survey for residential customer satisfaction covering 121 firms, of which 35 were members of Liberty's base panel, APS ranked 4th out of the 35 utilities in the base panel and 19th out of 121 utilities on a national basis.

- **Reliability**

  Liberty examined four standard industry measures of distribution system reliability – SAIFI (number of interruptions a customer sees in a year), SAIDI (number of interrupted minutes a customer sees in a year), CAIDI (number of minutes an average interruption lasts) and MAIFI (number of momentary interruptions a customer sees in a year). Based on available data compiled by EEI, APS compared far better than industry average in all four metrics.

- **Coal Plant Performance – Capacity Factor and Availability**

  Liberty examined the operational performance of the five Four Corners units, the three Cholla units, and the three Navajo units[6] in terms of Capacity Factor ("CF"), Equivalent Availability Factor ("EAF"), and Equivalent Forced Outage Rate ("EFORd") using the tailored panels described in II.B.i. Against these panels, Liberty found the CF of the Cholla and Four Corners units to be in the first quartile in the respective panels based on an average CF from 2005-2009. In addition, Liberty found that when compared to the GADS panel, the EAF of the units was generally better than the industry with the exception of Four Corners Unit 5, which was primarily due to very poor performance in 2008 and 2009. It should be noted, however, that Concentric disagrees with the formation of the base panel used by Liberty. This is further discussed in Section II.D below.

- **Coal Plant Fuel Costs**

  Liberty examined fuel costs at all of APS units over an unspecified period of time and found that all APS coal units were well below industry average in terms of fuel costs.

- **Coal Plant Non-Fuel Operating and Maintenance ("O&M") Costs**

  Liberty examined APS's non-fuel O&M costs on an individual plant basis without regard to APS's ownership share of each plant. Liberty found that APS's non-fuel O&M costs were below industry average on an individual plant basis.

- **Nuclear Fuel Costs**

[6] While APS owns 14% of the three Navajo units, Salt River Project is the operator of these units.

Liberty examined Palo Verde's fuel costs from 2001 - 2009 by trending these fuel costs on a $/MWh basis by year. Liberty found that APS has been close to the industry average over the past ten years. It should be noted, however, that Concentric disagrees with the formation of the base panel used by Liberty. This is further discussed in Section II.D below.

- **Transmission O&M**

  Liberty compared APS's Transmission O&M costs against the base panel on a per MWh sales basis for 2009 and on a dollar per line mile basis trended from 2000-2009. The results of Liberty's analysis showed that APS's costs were well below the industry average for both metrics.

- **Total Electric O&M**

  Liberty compared APS's Total Electric O&M costs (excluding power production) against the base panel. The major cost categories included in this metric were transmission, distribution, customer expense and administrative and general expense. On a total basis, APS's O&M costs were average against the base panel companies.

- **Total Electric Plant % Change**

  Liberty compared APS's average annual change in total electric plant from 2000-2009 against both the base panel and the high growth panel. In both cases, APS's investment in plant was reasonably aligned with the average of the panel companies.

- **Total Steam Production Plant**

  Liberty compared APS's average Steam Production Plant from 2000-2009 against the base panel in terms of both total dollars invested and on a per MWh of generation basis. Both metrics showed APS to be roughly equal to the panel average.

Hedging:

Liberty found that APS performance was strong with respect to policy level best practices and governance and operational parameters. This conclusion was consistent with the findings of past Liberty and RW Beck reviews.

Funds Paid Among Affiliates:

Liberty concluded that benchmarking does not shed much light on issues involving payments among affiliates and recommended a direct examination of the nature, extent, and pricing of

any interchanges among Pinnacle West enterprises only in the event that the Commission or stakeholders had a concern about cross subsidization potential.

ii. Areas of Below Average Performance

While APS's financial and operational performance was evaluated by Liberty and found to be at or above industry average in the areas shown above, there were several areas in which Liberty found APS's performance to be below average when measured against industry peers. These are described in further detail below.

Cost and Performance:

- **Coal Plant Operational Performance**

  Liberty reviewed the operation of each of APS's coal units using the tailored panels described in Section II.B.i. While Liberty found the capacity factors and availability of APS's coal units to generally compare well to the peer group, it found the Four Corners and Cholla units to be higher than their industry peers in terms of outage rates, with Four Corners Unit 5 having an especially high EFORd.

  While both Concentric, as well as APS recognize that these units have been operationally challenged over the past several years, we found several concerns with the analysis and findings, as further discussed in Section II.D.

- **Nuclear Plant Operational and Financial Performance**

  Liberty reviewed the operation of the Palo Verde nuclear units using the tailored panels described in Section II.B.i. Against these panels, Liberty found that the Palo Verde units did not compare well against their industry peers in terms of capacity factor, availability and outage rate.

  Regarding Palo Verde's financial performance, while fuel costs were found to be very close to industry average using Liberty's comparison panels, Palo Verde's operating and maintenance costs were found to compare less favorably to the nuclear units in Liberty's nuclear panel.

  As with the coal units, Concentric and APS recognize that Palo Verde has experienced performance and financial challenges over the past decade. However, we had several concerns with Liberty's analysis, as further discussed in Section II.D

- **Steam Production and Other Production Non-Fuel O&M**

  Liberty assessed APS's total steam production (coal-fired) O&M costs and other production (gas-fired) costs over a ten year period against the base panel companies in order to compare these costs on a company basis as opposed to a plant basis, which was the approach used for the coal and nuclear analysis described above. Liberty's findings for steam production showed that these costs were above industry average. For other production (gas-fired) costs, APS's costs were found to be above industry average over the last ten years. However, other production costs reported in FERC Form 1 information consist of numerous forms of generation, including both combined cycle and simple cycle gas fired units, and other types of costs[7]. In an effort to recognize these challenges, Liberty constructed a new panel of combined cycle units owned by regulated utilities and compared plants of similar size (+/- 30%) to two specific APS plants – Redhawk and West Phoenix 4 and 5. Liberty found that the non-fuel O&M costs of APS's plants were still high compared to the panel.

- **Distribution O&M**

  Liberty compared APS's distribution O&M costs to those of the base panel companies and found that they compared well to the base panel from 2000 – 2009 on total dollar per customer basis. However, Liberty raised concerns about spikes in 2007 and 2008 and recommended that APS analyze distribution O&M costs to determine the reasons for these spikes.

- **Customer Expense**

  Liberty examined APS's customer expense, defined as the sum of: i) customer accounts; ii) customer service; and iii) sales expense.[8] Liberty found that APS's customer expenses were far above the average of both the base panel and the growth panel on a per MWh sales basis as well as a per customer basis over the past decade. However, a review of APS's administrative and general ("A&G") expenses showed that APS has been far below the average of the base panel over the last ten years.

- **Nuclear Production Plant**

  Liberty found APS's average nuclear investment on a total dollars per year basis to be somewhat higher than its peers when compared to the nuclear panel over a 10 year period.

---

[7] APS includes the costs associated with its renewable programs in its other production costs

[8] These are all expenses charged to FERC accounts 901-917.

- **Transmission Plant**

  When compared to the average transmission plant and percent annual additions to transmission plant of the base panel companies from 2000 - 2009, Liberty found that APS was considerably higher than average.

- **Distribution Plant**

  Liberty reviewed the levels of APS investment in distribution using several metrics. Liberty presented distribution investment on a distribution plant per customer basis against the base panel, the high growth panel, and the regional panel. It also examined this metric as a function of service territory density and customer growth. Liberty found that by any measure, APS's distribution plant was significantly higher than the panel averages. Liberty acknowledged that APS's distribution plant has been high for many years, and reviewed additions to distribution plant in terms of capital expenditures as percent of distribution plant on average from 2000-2009 and found APS's investment to be higher than average as well. Furthermore, as required under the settlement agreement, Liberty examined distribution additions to plant per new customer against the base, high growth and regional panels and found APS's expenditures to be consistent with the industry average.

- **Management and Labor Expenses**

  Liberty examined APS's labor expenses in terms of number of employees and salaries and wages against its base panel. APS has a total of 6,800 employees, which was adjusted to an equivalent staffing level of 4,600 pursuant to a reconciliation of staffing performed by APS. Liberty's analysis showed that when staffing levels were examined on a per customer and per MWh sales basis, APS was higher than the average of the base panel companies. Based on these results, one would expect that the salaries and wages would be high as well. Indeed, salaries and wages on a per customer basis and a per MWh sales basis were significantly higher than the base panel. While Liberty claimed that APS's pensions and benefits were about 30% above the base panel average, it presented no data to support this statement.

Financial Benchmarks:

Liberty examined several financial metrics and found APS's long-term debt and commercial paper credit ratings to be comparatively low. In addition, it found that APS's Earned Return on Average Equity ("ROAE") and Earned Return on Average Assets ("ROAA") have fallen below those of the comparative panels from 2002-2009. High growth in APS's capital expenditures and operating expenses combined with historical test periods in rate cases have contributed to earnings attrition during this period.

Furthermore, Liberty found that APS's earnings growth rates were negative and below those of comparative panel members for 2000-2005, but have been at or near the base, expanded, nuclear and high growth panel averages for 2004-2009. APS as an investment for its parent was negative for the first half of the period and average for the past five years.

D. Concentric Review

Based on our review, we generally found Liberty's approach to the APS benchmarking study to be reasonable and consistent with industry practice. However, we had a number of specific concerns with its approach and analysis, which are discussed below.

i. Panel Design

The development of Liberty's base panel is consistent with Concentric's approach to the updated benchmarking study as presented in Section III. However, we disagree with Liberty's use of the expanded base panel as constructed. The expanded base panel included some gas utilities, because Liberty found the electric/gas differentiation for these utilities to be irrelevant. However, we believe that the inclusion of gas utilities in any comparison group to APS is inappropriate, since the cost structure of combination gas and electric utilities is significantly different than that of electric-only utilities. In addition, since the base panel includes 40 utilities, which provides for an ample number of companies on which to base a comparison to APS, we are unclear as to the value of using this expanded panel.

Regarding the use of tailored panels, while the use of tailored panels is standard practice in benchmarking studies, the tailored panels developed by Liberty are troublesome in that they do not provide a basis for an accurate comparison to APS. For example, Liberty developed a high growth panel in recognition of the challenges presented by APS's above average growth in terms of expenditures and capital investments. However, the high growth panel, which was defined by the growth in MWh sales from 1999-2007, contains companies with compound growth rates ranging from 4.54% to 2.36%. This extremely wide range in growth rates renders the use of these companies as a basis for comparison to APS to be inappropriate. In addition, a more appropriate measure of growth would be in terms of customer additions since this drives many of the cost related metrics and capital spending.

The use of a nuclear panel is reasonable considering that the ownership and operation of nuclear facilities as part of a company's generation portfolio adds costs and risks not faced by companies that do not own and operate such assets. However, there are several issues with the nuclear panel as constructed by Liberty. First, the nuclear panel does not make a distinction between fleet operators and non-fleet operators. Nuclear power generation requires specialized skills, knowledge and processes in many areas such as fuel procurement, refueling and maintenance, and operations. Companies owning and operating multiple nuclear plants (i.e., "nuclear fleets") have the capability to leverage and deploy these specialized skills, knowledge, and processes across the fleet and achieve economies of scale largely unavailable to those owning and operating a single plant. Thus, nuclear fleets are well positioned to achieve superior performance relative to plants operated by a company owning a single plant. Also, the nuclear panel includes the other owners of Palo Verde, which makes the comparison of APS's nuclear operations to the nuclear panel circular and erroneous. Finally, and most importantly, Liberty used this panel only to benchmark APS's investment in nuclear plant. The analysis of APS's nuclear operational and cost performance was based on two separately constructed panels as described above.

ii. Databases and Screens Used for Plant Performance

There were several issues with the panels and the underlying databases used to assess APS's coal and nuclear unit operational and financial performance: i) the databases used to develop the coal and nuclear unit panels used in the analyses included only units operated by the expanded base panel companies. It is unclear why Liberty did not use all units operating in the United States of similar size and technology to the APS's coal and nuclear units; ii) the databases used to develop the nuclear panels included nuclear generating units using both BWRs and PWRs, while Palo Verde uses only PWR technology; and iii) neither nuclear panel recognized the issue of including units owned by major fleet operators since there are distinct operational and cost advantages to companies owning a large fleet of nuclear units.

iii. Use of Performance Expectations

The only other issue we take with Liberty's approach to the benchmarking study is its inclusion of performance expectations based on APS's position in the relevant panel. For example, Liberty provided the following example of the process used in developing these expectations:

> *For example, APS might be the 4th largest in a panel, suggesting that APS should generally rank approximately 4th in terms of certain size-related performance measures (such as number of employees, total O&M costs, distribution investment, for example).*

This approach is problematic in that no company will track simplistic performance principle in each and every metric. Many factors can affect performance, and these factors can be

outside of the control of the company. Therefore, the application of such performance expectations is inappropriate.

iv. Study Findings

In the areas in which Liberty found APS to compare well against its peers, as shown in Section II.C.i, we generally concur with Liberty's findings. However, there were several areas in which Liberty found APS's performance to be either above or below average when measured against industry peers. In some cases, these findings were valid based on the comparison panels used and the data analyzed. In other cases, Concentric believes that the analysis was flawed in terms of approach, comparison panels and metrics. Concentric describes each of these areas in further detail below, and presents an alternate approach to evaluating these metrics and APS's performance in Section III.

Cost and Performance:

- **Coal Plant Operational Performance**

  Concentric has several concerns with the panels and the underlying databases used to assess the operational and financial performance of APS's coal units. In addition to the issues with the comparison panels, we have further concerns with aspects of Liberty's assessment of APS's coal unit performance. First, we believe it is inappropriate to include Navajo in any performance assessment. While APS owns 14% of Navajo Units 1 – 3, APS does not operate these units, and does not have direct control over their performance. Second, we believe that presenting a metric as an average over a specific time period can mask poor as well as good or improving performance. For all of metrics analyzed – capacity factor, availability, and forced outage rate – APS's coal units were compared to the peer group units based on an average of the metric over a five year period for the capacity factor and a ten year period for availability and forced outage rate. Even though the capacity factor and availability for APS's coal units were found by Liberty to be better than average, we maintain that a better presentation of the metrics is on a year by year basis, as shown in Section III.

  Regarding the forced outage rates for the Cholla and Four Corners units, which were found by Liberty to be higher than the average of the units in the comparison group, APS recognizes that these units have been challenged in this area over the past several years. APS has been proactive in its response to these performance issues. It recently completed extensive benchmarking studies to determine the root causes of these performance issues, and has implemented performance improvement strategies. A trending of these performance metrics, shown in Section III, displays a positive trend in forced outage rates.

While APS has demonstrated performance improvements at the Cholla and Four Corners plants, the challenges presented by coal quality have been difficult, and will continue to affect the operation of these plants in the future. Liberty did acknowledge the challenges presented by poor coal quality, but minimized the importance of the difficulties presented by low quality coal and further suggested that this was a new problem that primarily affected performance in 2010. In fact, low coal quality has been a challenge for APS for several years. Low quality coal can and typically does have a detrimental effect on unit operation, and results in higher outage rates and lower availability. Four Corners in particular faces even more challenges than Cholla since it is a mine mouth unit and does not have the flexibility to source various coals. As a result, when the coal at the mine is of low quality, the Four Corners units will likely experience poorer performance. The cost advantages of lower quality coal, as Liberty demonstrated in assessing APS's lower than average fuel costs, are to be expected to be partially offset by poorer unit performance.

- **Nuclear Plant Operational and Financial Performance**

  Concentric has several concerns with the panels and the underlying databases used to assess the operational and financial performance of APS's Palo Verde station. In addition, as with the coal units, Liberty presented the metrics analyzed – capacity factor, availability, and forced outage rate –based on an average of the metric over a three year period for the capacity factor and a ten year period for availability and forced outage rate. We will show these metrics using a trending approach year over year in Section III.

  Turning to financial performance, while fuel costs were found to be very close to industry average using Liberty's comparison panels, Palo Verde's operating and maintenance costs were found to compare less favorably to the nuclear units in Liberty's nuclear panel. It is unclear why Liberty separately analyzed plant operating and plant maintenance costs, since the allocation of costs to these accounts differs by company. Therefore, we believe operating and maintenance costs should be combined and compared to an appropriate peer group, as shown in Section III.

  In addition, Palo Verde is not located near a water supply, and must transport cooling water using over 35 miles of piping to provide a continuous flow of cooling water to the site. This adds more than $1/MWh to Palo Verde's operating costs. Because this is a cost incurred by APS that is highly unusual and outside of industry norm, this cost should be separately accounted for in Palo Verde's O&M costs in order to compare the plant to the peer group on an

equitable basis.

As with the coal units, APS recognizes that Palo Verde has experienced performance and financial challenges over the past decade. APS has taken steps to aggressively address these performance issues and has put programs in place to ensure that Palo Verde's performance is restored to at or above industry averages. Specifically, APS has addressed refueling outages to shorten them and improve plant availability and has aggressively invested in major equipment replacement such as new reactor heads and steam generators to address past underinvestment. In addition, APS has put in place an aggressive cost management and efficiency improvement program using benchmarking data from third-party sources. These efforts have resulted in a positive trend in plant performance, as shown in Section III.

- **Steam Production and Other Production Non-Fuel O&M**

Liberty assessed APS's total steam production (coal-fired) O&M costs and other production (gas-fired) costs in order to compare these costs on a company basis as opposed to a plant basis, which is in contrast to the approach used for the coal and nuclear analysis described above. Liberty's findings for steam production showed that these costs were above industry average. This is not surprising in that APS has a large ownership share of small, inefficient, high cost units that puts APS at a disadvantage when compared to the O&M costs of the companies in the base panel. A review of a company's total production O&M costs can be beneficial in getting a general sense of how a company's total O&M production costs compare to its peers. However, since these costs were examined on a power plant basis by Liberty, there was no added benefit to a high level review when a detailed review was already performed. Reviewing the costs on a company level is frequently problematic, as Liberty found. Many factors, included reporting differences and the inclusion/exclusion of certain costs in the FERC accounts, present problems when trying to perform an accurate comparison.

The problem of comparing production costs on a company basis was also apparent in Liberty's comparison of other production (gas-fired) costs. In this category, APS's costs were above industry average over the last ten years. However, other production costs reported in FERC Form 1 information consist of numerous forms of generation, including both combined cycle and

simple cycle gas fired units, and other types of costs[9]. The costs associated with operating various generation technologies vary widely, and do not provide any sound basis for comparison. While Liberty acknowledged this challenge and attempted to address it by constructing an alternative panel of regulated gas-fired units, we believe that this panel should not have been restricted to those combined cycle units owned by regulated utilities, but should have included units owned by unregulated entities as well. The results of this alternate analysis are presented in Section III.

- **Distribution O&M**

  Liberty found that APS's distribution O&M costs compared well to those of the base panel. However, Liberty raised concerns about spikes in 2007 and 2008 and recommended that APS analyze distribution O&M costs to determine the reasons for these spikes.

  As explained to Liberty by APS in the process of conducting the study, the spikes in 2007 and 2008 were largely due to a one time severance charged to the distribution O&M account, vegetation management expenses, and expenses related to the Bark Beetle problems in the region. The cost to address the bark beetle issue was 20% of the total cost of overhead line maintenance in 2008.

  It is important to note that a majority of APS's distribution system is underground which makes system maintenance more demanding in terms of cost as compared to almost all of the utilities in the base panel. Even with this challenge, APS's distribution O&M costs have largely been below industry average over the past decade, as discussed in Section III.

- **Customer Expense**

  Liberty examined APS's customer expense and found that APS's customer expenses were far above the average while APS's A&G expenses were far below average. This is not surprising since, according to the participation agreements between the co-owners of Palo Verde and Four Corners, APS must functionalize shared services expenses to the accounts related to the functional areas of the groups supported. These expenses are not charged to A&G accounts, which is how other companies with shared services expenses record these costs. As discussed and presented in Section III, a reasonable approach to benchmarking APS's total customer expenses is to combine APS's customer

[9] APS includes the costs associated with its renewable programs in its other production costs

and A&G expenses to eliminate this reclassification difference between APS and the comparable companies.

- **Nuclear Production Plant**

  Liberty found that APS's average nuclear investment on a total dollars per year basis was somewhat higher than its peers. However, we believe a more reasonable approach would be to measure investment as a function of unit size. When measured on a total dollars per "MW" basis, Palo Verde is very close to the average when compared to a more appropriate panel, as further discussed in Section III.

- **Transmission Plant**

  When compared to the average transmission plant, Liberty found APS to compare favorably to the base panel. When Liberty analyzed APS's percent annual additions to transmission plant against the base panel companies from 2000 - 2009, Liberty found APS's investment in transmission plant to be considerably higher than average. However, placing these metrics on a total dollar invested basis does not recognize the size of the transmission system. When presented on a length of transmission lines basis, APS's total transmission plant compares favorably to the industry average. When percent annual additions to transmission plant are trended, APS's investment has come into line with the panel averages, as shown in Section III.

- **Distribution Plant**

  Liberty reviewed the levels of APS investment in distribution using several metrics and found that by any measure, APS's distribution plant was significantly higher than the panel averages. Liberty acknowledged that APS's distribution plant has been high for many years. Pursuant to the settlement agreement, Liberty examined distribution additions to plant per new customer against the base, high growth and regional panels and found APS's expenditures to be consistent with the industry average. However, Liberty dismissed these results as misleading and found that when examined on the basis of total number of customers, APS's investment in distribution was still high.

  Concentric takes exception to Liberty's dismissive nature of the history of APS's high levels of distribution plant. When examined on a percent additions to total distribution plant by year, APS is marginally above its peers from 2000-2008 and has trended down to below average in the last two years, as further shown in Section III. In addition, due to the relatively new age of APS's distribution system as a result of the high customer growth experienced over

the last decade, APS has a less depreciated system and therefore its net plant will naturally be higher than its peers.

- **Management and Labor Expenses**

  Liberty examined APS's labor expenses in terms of number of employees and salaries and wages and found that APS was significantly higher than the average of the base panel companies. Our review of Liberty's approach revealed a significant flaw in the use of the base panel against which to assess APS's staffing and salaries and wages levels. Over 95% of Pinnacle West's operating revenues come from APS's electric utility operations and all of the employees and associated salaries, wages pensions and benefits are reported by APS in the FERC Form 1 data. However, many of the companies in the base panel have shared services[10] provided by the parent company or power provided by separate generating companies and do not report these employees or the costs associated with these employees as part of the electric utility FERC Form 1 data. A more appropriate approach to assess this metric would be to develop a panel of electric holding companies with at least 70% of revenues from electric utility operations, and include pensions and benefits in the analysis. Concentric shows the results of this analysis in its updated benchmarking study in Section III.

Financial Benchmarks:

Generally, Concentric found that Liberty focused on the appropriate metrics related to financial health of a utility. In particular, Liberty focused on standard financial performance measures such as return on assets and return on equity, funds flow from operations as it relates to debt levels and interest costs, debt to capitalization levels, and cash flow to capital expenditure levels. Equity investors, and to a slightly different degree debt investors, focus on these metrics as they evaluate their interest in owning the securities of a company.

Liberty found that APS's equity and asset return levels were low relative to the companies in the base panel. Liberty also found that APS's bond credit ratings, at BBB-, are one and a half steps below that of Liberty's base panel of companies, where the bond credit ratings average between BBB and BBB+. Liberty also noted that (high) debt leverage (at 58.3% of capitalization including the impact of "imputed debt" using the S&P method) "has been a drag on APS credit ratings for several years" and "debt levels need to improve for credit upgrades".[11] Based on these findings, Liberty provided three recommendations relating to this

[10] Shared services are those functional areas that provide services across multiple business units within a company such as accounting, legal, taxes, etc.

[11] Liberty Benchmarking Study, page 44

financial section of its analysis: i) evaluate specific drivers and causes for consistently low APS rates of return; ii) determine how the credit rating effects of power purchase agreements, operating leases and pension/other post-employment benefits ("OPEB") may be economically mitigated; and 3) determine whether the APS's targeted adjusted debt level of 52 percent will provide improved credit ratings results.

Concentric does not disagree with the direction of Liberty's recommendations. We believe a review of Liberty's findings in this area suggests Liberty has identified the key issue associated with APS's historically subpar financial performance. The key issue is earnings attrition due to regulatory lag. Regulatory lag in Arizona has traditionally been significantly longer than nearly any other jurisdiction according to data compiled by Regulatory Research Associates ("RRA"), as further described in Section III. In the most recent rate case in front of the ACC, an order was issued within 21 months of filing. While the rate case lag was still substantial, in this case, the ACC permitted rate recognition of certain post-test-period adjustments, which mitigates some issues associated with regulatory lag. It is surprising, therefore, that Liberty sees the need to "evaluate specific drivers and causes" for APS's earnings attrition.

III. CONCENTRIC UPDATED 2010 BENCHMARKING STUDY

A. INTRODUCTION AND APPROACH

Concentric's overall approach to conducting the updated study involved an assessment of APS's productive efficiency relative to comparable groups of companies in specific years and across time in order to measure APS's performance in fulfilling its cost obligations. In addition, in order to assess whether any cost improvements that may have been achieved were done at the expense of reducing customer service or reliability, we assessed specific service quality metrics. We then developed a situational assessment to recognize that the cost advantages or disadvantages that many utilities face are the product of circumstances beyond their control. The situational assessment examined these exogenous factors, which were then used to place a utility's cost performance in the context of the market it serves.

i. Panel Selections

The first step in performing the updated benchmarking study involved developing the composition of the peer groups used to compare to APS. Our objective in determining the sample set of electric utility companies was to achieve the largest group for which consistent data were available and which was operationally similar to APS. APS is an electric-only utility with over 1,000,000 customers and ownership in generating resources. Therefore, we established a group of companies with electric-only utility operations who have at least 300,000 customers and own generating resources. We did not include gas utilities in any comparison group to APS, since the cost structure of combination gas and electric utilities is significantly different than that of electric-only utilities. We define this group of 39 comparable companies as the "Base Panel." This Base Panel contains the same companies as Liberty's base panel, with the only difference being Liberty's inclusion of the Salt River Project in its base panel pursuant to the settlement agreement.[12]

In addition, we established a panel of other investor-owned electric utilities subject to the same jurisdictional authority. This "Regional Panel" includes the same nine companies contained in Liberty's regional panel.

While Liberty also created a high growth panel and a nuclear panel, for reasons discussed in Section II.D, we did not see the value in a high growth panel. However, we did create a nuclear panel for the purpose of comparing Total Non-Fuel O&M expenses. This panel consisted of Base Panel companies that own units that are part of a fleet operation, and excluded owners whose only nuclear ownership was in the Palo Verde plant.

[12] Since data for Salt River Project are not available beyond 2004, we did not include it in our Base Panel.

Overall, our comparisons panels are generally limited to the Base Panel and the Regional Panel for the total benchmarking assessment.

v. Selection of Metrics

After we developed our comparison panels, we defined the operational, financial and reliability/service quality metrics that were to be used in the benchmarking study. We compiled data from various sources to provide sufficient metrics to assess APS's overall performance relative to the comparable groups. Similar to Liberty, we relied on FERC Form 1 reports (as reported by SNL Financial). For supplemental metrics related to APS's operational and service quality performance, we used NERC GADS data as well as Edison Electric Institute ("EEI") data. We then defined the timeframe over which the analysis was to be performed. In general, we used the same time frame used by Liberty, 2000 - 2009, and added 2010 data. In some cases, such as for generating unit performance and reliability measures, data were only available for the most recent five years. We generally used the same operational and service quality metrics used by Liberty. However, there were some minor differences, as discussed in more detail below.

vi. Data Analysis

Following the selection of the metrics to be used, we developed merit order benchmarking results for the companies in the comparable groups in terms of operational and cost performance based on these metrics. In assessing APS's service quality, we compared customer satisfaction and distribution system reliability using the JD Power survey results to assess customer satisfaction and industry-wide EEI data to assess reliability. This is consistent with Liberty's approach.

In assessing operational performance, we developed coal panels based on comparable unit sizes and nuclear panels based on comparable unit technology, while Liberty restricted its coal and nuclear panels to those units owned by the companies in its expanded base panel. In addition, while Liberty showed averages of APS's generating unit performance metrics against a 10 year average of the units in the comparable panel, we showed year by year performance for each metric to capture important trends.

In assessing cost performance, we measured the level of cost input per unit of "output" in the same way Liberty did, such as customer service expense per customer, or O&M expense per MWh sold. While we present these cost diagnostics individually by rank or merit order, Liberty did not present a ranking of APS against the peer group companies in these metrics, but rather presented the average of the metric for APS against the average of the metric for the peer group companies. Finally, in order to develop an "overall" assessment based on rank order, we took an average of all the rank order values and developed a merit order based on those averages. This approach shows APS's relative overall merit order. Liberty did not present an overall ranking.

Finally, in recognition of the significantly different service area characteristics that the peer group members face, and the diverse performance challenges created by these service area characteristics, we developed a situational assessment ranking which reflects the degree of difficulty that each peer group member faces in seeking to maximize its productive efficiency. We used the same method described above to rank the level of challenges to performance that different companies face in order to put the benchmarking results in context. Liberty did not conduct a situational assessment.

B. Situational Assessment

As noted above, the purpose of the situational assessment is generally to provide insight into the companies' operations and, in turn, offer context and a deeper understanding of their performance and costs. The situational assessment helps to explain the challenges a utility faces in keeping costs low. Concentric's situational assessment considered ten specific metrics which were used to evaluate APS's business and operating environment relative to the various peer groups companies. For each metric and comparison group, we developed a rank order of the companies as well as an overall score based on the average rank. In this study, a high-ranking of "1" indicates the highest level of challenges. The more challenged a company is, the greater the difficulty can be expected in controlling costs. These factors largely represent exogenous factors that are defined by the company's customer base and service area, and are beyond the company's control.

The results of the situational assessment are shown in Exhibits 1 and 3, and a summary of each metric is provided below:

- **Percent Sales Residential**

  Nearly half of APS's sales by volume are sales to residential customers. APS is consistently in the top quartile of residential sales in both the Base and Regional Panels. In general, residential customers are more expensive to serve than commercial and industrial customers (driven by, e.g., customer-related expenses, load factor considerations). As a result, utilities with a higher proportion of residential customers tend to have higher costs.

- **Percent Sales Other**

  Other sales represent all sales other than those to residential, commercial, and industrial customers. This category also includes Sales for Resale. APS, with a very low volume of other sales, is in the top quartile of the Regional Panel and consistently ranks first or second in the Base Panel. These results are consistent with APS's ranking in the Percent Sales Residential metric.

- **Use per Customer**

Use per customer measures the average volume of sales to each customer. Since many of the costs of serving an individual customer do not vary with the level of consumption, utilities with lower use per customer levels tend to be higher cost operations. APS is consistently in the second quartile of the Base Panel. In the Regional Panel, APS's use per customer is comparable to the regional companies.

- **Change in Customers (%)**

  Increases or decreases (in absolute percentage terms) in the number of customers create challenges in terms of managing capital expenditures, plant utilization and fixed cost amortization. APS's customer growth rate has historically placed it in the top quartile of the Base and Regional Panels. However, APS growth rate has tempered somewhat in the most recent two years, where APS has ranked in the second quartile of the Base and Regional Panels.

- **Change in Sales Volume (Rolling Five Year Average)**

  Like changes in customer base, dramatic shifts in sales volume pose challenges to any company. When measured on a rolling five year basis[13], APS's change in sales volume has placed it in the top quartile in the Base Panel in ten of the last eleven years and the top quartile in the Regional Panel in eight of the last eleven years.

- **Customer Density**

  The customer density within a utility's service territory is an important factor in assessing the cost of serving customers. Companies whose service territory is more spread out require more infrastructure to provide service to customers and therefore incur higher costs. APS has a significantly more rural service territory when compared to both the Base and Regional Panels. APS has ranked in the top quartile in the Base Panel in each of the last eleven years and in the top quartile in seven of the last eleven years in the Regional Panel.

- **Percent Generation Nuclear**

  The costs for nuclear generation are comparatively higher than coal-fired, oil-fired, gas-fired and hydroelectric generating resources. APS has a higher percentage of its generation produced by nuclear resources than its peers in any of the comparison groups. APS has ranked in the second quartile over the last eleven years in terms of percentage nuclear generation in the Regional and Base

[13] This metric is calculated by comparing the current year sales volume to the average of the previous five years sales volume to calculate a percent change.

Panels. This places significant pressure on APS' cost structure and its ability to maintain competitive rates relative to its peers in the region.

- **Energy Losses**

  Energy losses are a product of the transmission and distribution infrastructure through which the energy is transmitted. Electric utilities which are more transmission dependent experience higher losses than utilities which are able to site generation closer to load centers. While APS has historically not been challenged in this area, it has been in the second quartile in four of the last five years in the Base Panel.

- **Depreciation to Gross Plant**

  This metric is a reasonable proxy for the age of a utility's asset base. Utilities with a higher proportion of accumulated depreciation to gross plant have delivery systems which tend to be older. Older systems tend to require more costly maintenance. This metric shows that APS has relatively newer infrastructure when compared to the Base and Regional Panels. This indicates that APS has not been challenged in terms of higher maintenance costs.

- **Regulatory Lag**

  Regulatory lag, as measured by rate case lag, represents the time it takes for a utility to recover through rates costs incurred to provide service to their customers, which impacts the financial health and capability of the utility. This metric represents the challenge that a utility faces in terms of regulatory uncertainty and cost recovery. Since 2006, APS has had the highest rate case lag in either the base panel, or the regional panel.

It is important to keep the situational assessment in context. We offer these metrics as a means of getting the lay of the land in better understanding the productive efficiency metrics. This is not a perfect means of capturing all of the challenges or advantages of the companies in the comparable groups, but represents a reasonable cross-section of publicly available measures of a utility's operating environment. While only a high-level snapshot, these data indicate that APS is consistently one of the more situationally-challenged companies within the comparison groups, as shown below.

TABLE 6: SUMMARY OF SITUATIONAL ASSESSMENT RANKINGS

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
APS in Base Panel	9	6	6	5	8	6	4	2	1	2	3
APS in Regional Panel	3	2	3	3	3	3	1	2	1	2	1

C. Productive Efficiency Assessment

To assess APS's cost performance, we created unique categories of metrics against which to compare APS's performance to the two different peer groups across the 11-year study period.[14] By comparison, Liberty used similar metrics to assess APS's cost performance, although some of these metrics differed slightly.[15] In our productive efficiency assessment, a ranking of "1" indicates that the company is more efficient than the companies in the peer group. Exhibit 2 shows the merit order rankings for each company, on each metric, for each year. The underlying values for the productive efficiency metrics are provided in Exhibit 3. It should be noted that Liberty did not provide such a ranking, but rather showed its metrics on an average basis against the entire peer group average.

Concentric measured APS's performance across a variety of expense categories. Similar to Liberty, we included high-level measures, such as total non-fuel O&M expenses, as well as various subcategories. Most metrics are calculated on an expense per customer or an expense per MWh sold basis. The productive efficiency metrics presented in the analysis are an average of the per-customer values and the per MWh values for each cost element. For example, the Customer/A&G expenses metric reflects each utility's Customer/A&G expenses per MWh sold and Customer/A&G expenses per customer, and presents the average performance rank on these two metrics as the measure of Customer/A&G productive efficiency. To ensure that APS's performance on cost metrics did not occur at the cost of lower reliability or customer satisfaction, we also compiled a variety of metrics to measure APS's operational and service quality performance. The detailed definitions of each of the productive efficiency, operational and service quality metrics used are presented in Exhibit 3 and are described below.

- **Production O&M expenses**

  APS has shown consistent improvement in its Production O&M performance relative to the comparison groups. APS has consistently been in the second and third quartile for the Base Panel on a per customer basis.

  Liberty did not review Production O&M expenses on a total basis, but rather reviewed these expenses separately for steam production (coal-fired), other production (gas-fired), and nuclear production. The only category in which Liberty found APS's expenses to be unusually high was nuclear production. However, as discussed previously, Liberty analyzed nuclear plant operating and plant maintenance costs separately, and did not adjust for the cost of providing

[14] Concentric did not create metrics to assess the financial health of APS as Liberty was required to do pursuant to the settlement agreement.

[15] Liberty's metrics were largely dictated by the settlement agreement, while we used metrics that we consider to be most relevant in assessing a company's ability to control costs.

cooling water to the plant. As shown in Attachment B, when we make these adjustments and compare nuclear O&M costs against the peer group of units used in our performance analysis, as discussed below, APS's nuclear O&M costs compare much more favorably, ranking no worse than the third quartile for seven of the eleven years included in the study.

- **Transmission O&M expenses**

  In addition to the per-customer and per-MWh cost measurement used in other metrics, our overall merit-order ranking for Transmission O&M also takes into account Transmission O&M expenses per mile of transmission line. APS has consistently been in the second or third quartile of the Base Panel across all measures and in the first or second quartile in the Regional Panel by all measures over the last ten years. In 2010, APS achieved its best performance to-date relative to each of the comparison groups across all measures, ranking in the first quartile for the Regional Panel, and the second quartile for the Base Panel.

  Liberty compared the APS's transmission O&M costs to those of its base panel companies on a per MWh sales basis and per line mile basis and found APS's transmission O&M expenses to be below industry average.

- **Distribution O&M expenses**

  APS's distribution system has a large percentage of its infrastructure underground. This would suggest all else being equal, that APS Distribution O&M expenses would be higher than a utility with a largely above-ground distribution system. As shown in Attachment C, APS has the second-highest percentage of its distribution system underground of all utilities reported. However, APS has been in the second or third quartile of the Base Panel and the Regional Panel in terms of Distribution O&M expenses for all years on both a per customer and per MWh sales basis, demonstrating the Company's success at managing costs in this area.

  Liberty compared APS's distribution O&M costs to its base panel and high growth panel companies on a per customer basis and found APS to be competitive against both.

- **Customer and A&G expenses**

  Liberty reviewed customer expenses on a per MWh sales basis and a per customer basis against both its base and high growth panels and found them to be far above the panel averages. It also reviewed APS's A&G expenses on a per MWh sales basis against its base panel and found them to be far below the panel average in most years. As previously discussed, the participation agreements

between the co-owners of Palo Verde and Four Corners require APS to functionalize shared services expenses to the FERC customer accounts related to the functional areas of the groups supported, and not charge these expenses to A&G accounts, which is how other companies with shared services expenses record these costs. Given these facts, a reasonable approach to benchmarking APS's total customer expenses is to combine customer and A&G expenses to eliminate this reclassification difference between APS and the comparable companies. Based on this approach, APS has consistently been in the second or third quartile in the Base Panel, and the second quartile in the Regional Panel in each of the last seven years.

- **Total Non-Fuel O&M Expenses**

  Overall, APS has performed well in controlling Total Non-Fuel O&M expenses, falling in the second or third quartile of the Base Panel and Regional Panel in ten out of eleven years on a per customer and per MWh sales basis. Compared to the Nuclear Panel, APS ranks much more favorably, with an overall rank of one or two against the comparison companies.

- **Plant Investment**

  Liberty reviewed APS's overall Plant Investment and Plant Investments in a number of functional areas. Liberty noted APS has high levels of nuclear plant and distribution plant by measures of accumulated plant, and high levels of transmission new capital expenditures.

  Similar to Liberty's approach, Concentric looked at the overall level of investment for Production, Transmission, Distribution, and Total Electric Plant compared to existing plant balances. Production Plant Investment was in line with the Base Panel and the Regional Panel ranking in the first or second quartile for eight of the eleven years in the study period. However, Transmission Investment trends higher than the peer groups. Importantly, since 2006, APS has not dropped below the third quartile of the Base Panel which demonstrates the level of Transmission Investment has trended closer to the comparable group mean.

  Distribution Plant Investment was especially high in prior years, specifically 2000 through 2007, when it was ranked in the fourth quartile of the Base Panel. However, this can be expected due to APS's high customer growth over those years. Since 2007, APS's Distribution Plant Investment has moderated. On a Total Electric Plant basis, APS's level of Plant Investment has been consistent with the Base Panel, ranking in the second and third quartile in the Base Panel, and improving over time. Overall, APS's capital spending has been consistent

with industry averages, and has decreased relative to comparable companies in recent years.

- **Labor Efficiency**

  Liberty reviewed employee costs by analyzing APS's staffing levels on an employee per customer basis and employee per MWh sales basis compared to its base panel companies and found APS to be well above the average of the base panel. In addition, Liberty analyzed APS's salaries and wages on a per customer and per MWh sales basis against its base panel companies and found APS to be approximately 30% higher than the base panel average. However, as discussed above, we found Liberty's approach to be flawed in the use of the base panel against which to assess employee costs.

  Our standard approach to evaluating employee costs is to assess this cost in terms of Labor Efficiency. Labor Efficiency is a metric that combines Salaries, Wages, Pensions, and Benefits per Customer and Employees per Customer. Because utility companies vary greatly in organizational structure, and employees may be reported at different levels of a given company's organizational structure, comparisons to the Base Panel and Regional Panel were inconsistent. To reduce the potential incongruities between reporting structures, Concentric developed a panel of comparable companies, specifically for this metric, at the holding company-level. We used holding companies so that any job functions shared across various divisions of the company would be accounted for, and also would not be double-counted. The comparable group included companies, like Pinnacle West Capital, that are primarily engaged in electric utility operations. As shown in Attachment D, using this comparable group, APS, as represented by Pinnacle West Capital, ranked in the second and third quartiles for Employees per Customer and its Salaries, Wages, Pensions, and Benefits per Customer were reasonable.

- **Nuclear Plant Performance**

  As noted in the Liberty Study and acknowledged by APS, the performance of the Palo Verde units has left room for improvement. However, as noted in Section II.D, above, it is important to benchmark APS's nuclear operating performance against an appropriate nuclear peer group – one that includes all PWR units greater than 1,000 MW. When benchmarked against this nuclear peer group using data from the GADS database from 2005-2010, the results of APS's efforts to improve the performance of the Palo Verde units are evident. Palo Verde's EAF has gone from a low of 70% in 2006 to 89% in 2010 against an industry average of 87%. Similarly, in terms of outage rates, Palo Verde's EFORd has dropped dramatically from 14% in 2006 to 1.8% in 2008 against an industry average of 4.8%. Palo Verde's CF has gone from below the industry

average in 2006 to above the industry average in 2010.[16] Due to shorter refueling outages and investments in major equipment replacements, the Palo Verde station has show dramatic improvement in terms of availability, outage rates, and capacity factor, and continues to make significant operational improvements as shown in Attachment E.

- **Fossil Plant Performance**

As previously discussed, APS recognizes that the coal units have been faced with performance challenges over the past several years. APS has been proactively addressing these challenges by uncovering the root causes of the performance issues and implementing improvement strategies. Liberty's findings reflected these challenges. However, as previously discussed above, it is important to benchmark APS's coal unit operating performance against an appropriate peer group – one that does not limit the peer group to units owned by the expanded base panel companies and includes screens for size.

For Cholla Units 1-3 and Four Corners Units 1-3, a comparison to coal-fired units contained in the NERC GADS database between 100MW and 300MW using data from 2005-2010 shows that both the Four Corners and Cholla plants have experienced some variability in terms of EAF[17]. The Cholla units have been more consistent in terms of EFORd and CF, with the exception of Cholla Unit 2 which experienced a major equipment failure and significant outage in 2010. When compared to coal-fired units contained in the NERC GADS database between 600MW and 1,000MW, the Four Corners Units 4 and 5 have historically been at or near industry average, while Unit 5 has historically been more challenged in terms of EFORd and CF. These operation metrics are shown in Attachment F.

While APS has demonstrated performance improvements at its coal-fired stations, the challenges presented by poor coal quality will continue to be an issue for APS. Low quality coal frequently has a negative effect on plant operations. Since APS's coal units do not have supply flexibility, the performance of its fossil units is a direct result of the quality of the coal at the mine where the plant is located. This has a negative impact on fossil plant O&M expenses, but is offset by substantially lower fuel costs. It is important to highlight that the availability of the units has compared favorably despite having higher than average forced outage rates, which is a reflection of APS's ability to return the units to service quickly.

[16] Palo Verde operational statistics from 2005-2010 were provided by APS.
[17] Coal plant operational statistics from 2005-2010 were provided by APS.

D. SERVICE QUALITY ASSESSMENT

It is important to assess whether a particular company has successfully achieved both its cost and service obligations. In addition to productive efficiency, we evaluated APS's quality of service in terms of system reliability and customer service quality.

- **Distribution system reliability**

  Similar to the Liberty approach, we considered four measures in assessing distribution system reliability: (i) Distribution System Average Interruption Frequency Index ("SAIFI") is defined as the number of interruptions a customer sees in a year; (ii) Distribution System Average Interruption Duration Index ("SAIDI") is defined as the number of interrupted minutes a customer sees in a year; (iii) Customer Average Interruption Duration Index ("CAIDI") is defined as the number of minutes an average interruption lasts; and (iv) Momentary Average Interruption Frequency Index ("MAIFI") is defined as the average number of momentary interruptions that a customer would experience during a given period (typically a year). In analyzing SAIFI, APS has consistently outperformed the industry in each year since 2005. Similarly, APS's SAIDI has been in the top quartile in each year over the last five years. APS's CAIDI has been outstanding against industry peers in each year over the last five years. Finally, APS' MAIFI has been far below the industry average in each year since 2005. These metrics indicate that APS is providing high quality service to its customers in terms of reliability.

- **Customer service quality**

  Consistent with the Liberty approach, Concentric reviewed the 2010 JD Power survey for residential customer satisfaction as a measure of APS's relative customer service quality. The JD Power survey measures customer satisfaction of electric utility companies by examining six key factors: (i) power quality and reliability; (ii) price; (iii) billing and payment; (iv) corporate citizenship; (v) communications; and (vi) customer service. Based on the results of this survey, APS ranks in the top quartile of base panel companies, and 19th out of 121 utilities across the nation.

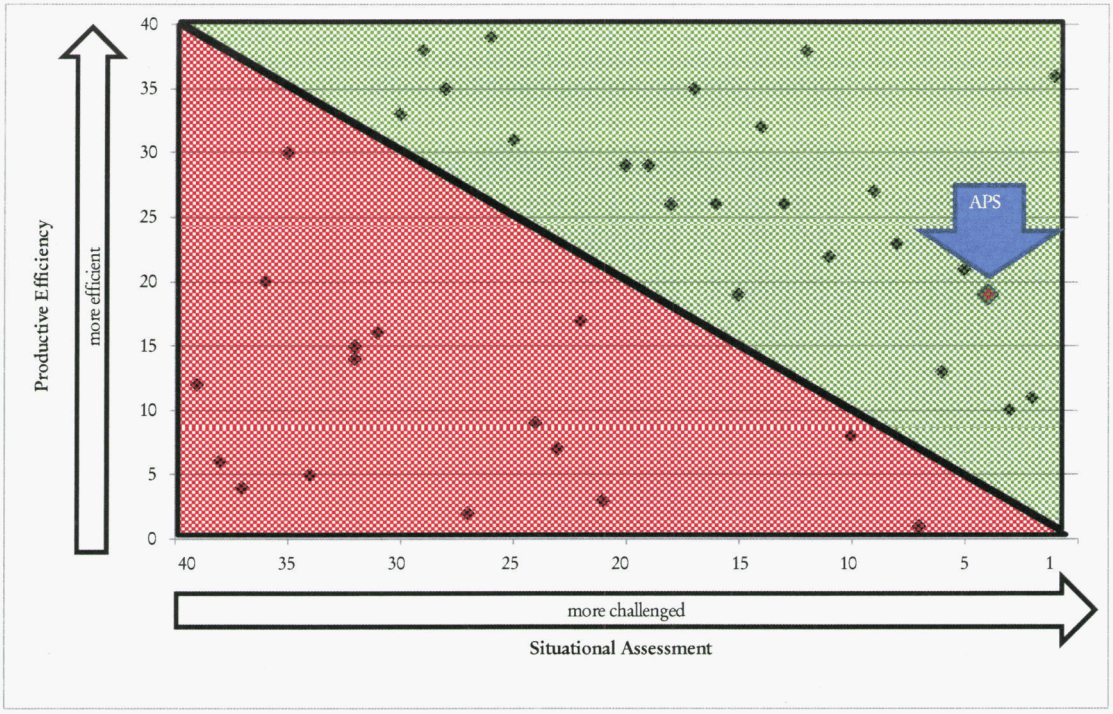
IV. CONCLUSIONS

As shown in Exhibit 2, APS has ranked in the second and third quartile in ten out of eleven years in the Base Panel and ranks between the first and third quartile in the Regional Panel in terms of productive efficiency over the course of the study. Most importantly, APS's performance on the productive efficiency benchmark has not occurred at the expense of service reliability or customer satisfaction.

It should be noted that these results are based entirely on the ranking of the performance metrics, without any adjustment made for the challenges demonstrated in the Situational Assessment. While the situational assessment is not a perfect means of capturing all of the challenges or advantages of the companies in the comparables groups, it does represent a reasonable cross-section of publicly available measures of a utility's operating environment. While only a high-level snapshot, these data indicate that APS is consistently one of the ten most "situationally-challenged" companies within the Base Panel and one of the top three "situationally challenged" in the Regional Panel, as the results show in Exhibit 1.

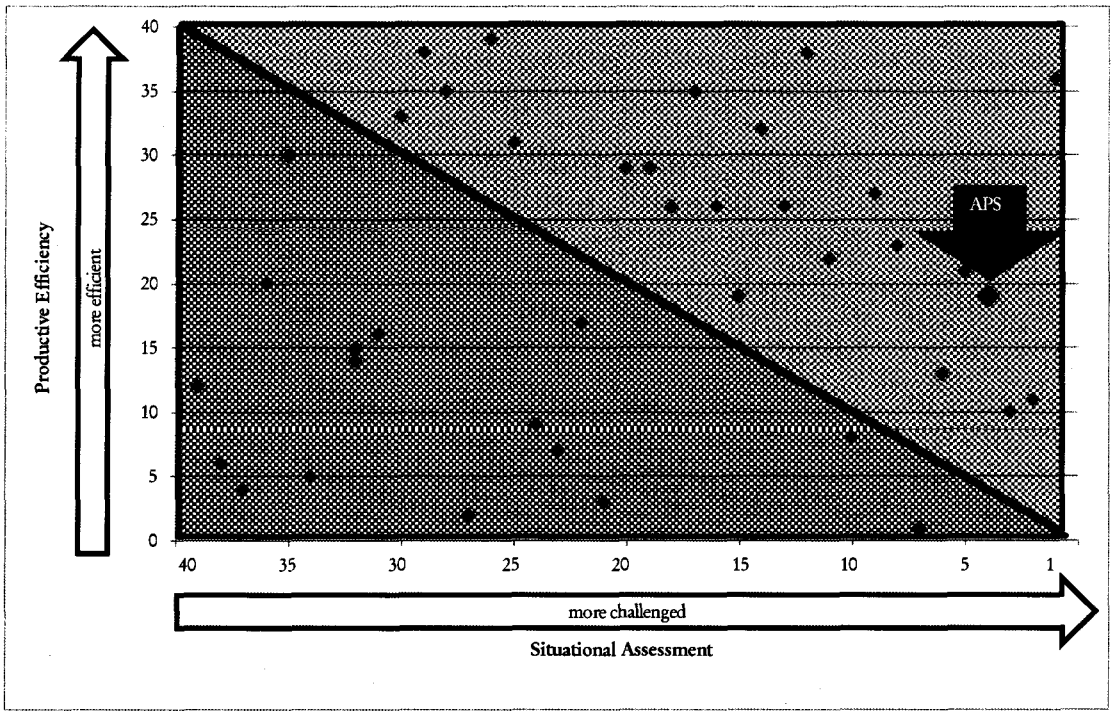
Considering both the challenges identified in the situational assessment and the productive efficiency ranks from the benchmarking analysis is a valuable exercise in putting APS's performance in context. Figure 1 combines the productive efficiency merit order rankings and the situational assessment rankings. When viewed on these axes, a bandwidth around the diagonal line running from the upper left corner to the lower right corner reflects the utilities whose productivity is consistent with the challenges identified in the situational assessment. The further away (either above or below) that a utility's performance is from this line, the more exceptional is its performance (either exceptionally good or exceptionally poor).

FIGURE 1: COMBINED ASSESSMENT 2010



As shown above, APS's performance in 2010 was exceptionally good, and APS outperformed its Base Panel peers on a basis which considers both absolute productivity measures and the relative challenges it faced.

FIGURE 1: COMBINED ASSESSMENT 2010



As shown above, APS's performance in 2010 was exceptionally good, and APS outperformed its Base Panel peers on a basis which considers both absolute productivity measures and the relative challenges it faced.

Situational Assessment Rankings - 2000

(a rank of 1 indicates the most challenged performer for each metric)

Base Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*4*	*35*	*11*	*4*	*2*	*7*	*31*	*32*	*4*	*31*	*16.1*	*9*
Alabama Power Company	24	19	36	24	14	15	38	31	11		23.6	35
Appalachian Power Company	8	17	21	31	36	18	16	27	8	14	19.6	25
Carolina Power & Light Company	16	22	29	7	25	5	32	9	19		18.2	18
Columbus Southern Power Company	10	13	10	8	27	18	22	29	28	11	17.6	15
Dayton Power and Light Company	21	16	16	37	37	18	9	13	24	16	20.7	28
Detroit Edison Company	34	7	7	33	29	16	13	21	34	26	22.0	31
Duke Energy Carolinas, LLC	27	6	32	10	30	4	20	24	13	26	19.2	23
Duke Energy Indiana, Inc.	30	34	31	14	22	18	7	22	23	6	20.7	28
El Paso Electric Company	31	32	4	12	31	1	23	1	7	3	14.5	4
Entergy Arkansas, Inc.	13	33	18	35	18	3	18	14	3	11	16.6	12
Entergy Louisiana, LLC												
Entergy Mississippi, Inc.	6	12	22	18	16	18	4	34	9	31	17.0	13
Florida Power & Light Company	1	2	5	9	19	9	8	3	33		9.9	2
Florida Power Corporation	2	14	9	19	12	14	14	5	30	22	14.1	3
Georgia Power Company	33	5	35	11	7	13	11	26	20	26	18.7	20
Gulf Power Company	3	24	13	13	4	18	29	19	10	22	15.5	6
Idaho Power Co.	29	25	33	6	5	18	12	33	1	22	18.4	19
Indiana Michigan Power Company	32	18	24	36	32	12	15	7	22	4	20.2	27
Indianapolis Power & Light Company	22	8	23	25	35	18	26	15	36	15	22.3	32
Kansas City Power & Light Company	20	9	19	27	6	11	21	30	16	33	19.2	23
Kansas Gas and Electric Company	23	10	20	26	23	8	1	37		5	17.0	13
KCP&L Greater Missouri Operations Company	7	23	6	38	26	18	3	12	27	20	18.0	17
Kentucky Utilities Company	19	37	30	17	11	18	24	8	17	8	18.9	22
Monongahela Power Company	36	15	17	2	3	18	28	11	6	16	15.2	5
Nevada Power Company	5	3	15	3	1	18	27	38	25	26	16.1	9
Ohio Power Company	37	28	37	34	38	18	30	10	18	20	27.0	38
Oklahoma Gas and Electric Company	17	11	27	1	15	18	17	6	29	22	16.3	11
PacifiCorp	35	36	25	22	34	38	19	35	2	19	26.5	37
Portland General Electric Company	9	30	12	20	9	18	35	16	32	6	18.7	20
Public Service Company of New Hampshire	15	29	1	23	24	17	33	4	14		17.8	16
Public Service Company of New Mexico	26	38	2	15	20	10	36	23	31	11	21.2	30
Public Service Company of Oklahoma	14	4	28	29	10	18	5	18	21	8	15.5	6
Southern California Edison Co.	25	1	3	28	8	2	2	2	15	1	8.7	1
Southwestern Electric Power Company	28	26	34	32	33	18	34	20	12	10	24.7	36
Southwestern Public Service Company	38	27	38	21	28	18	6	28	5	26	23.5	34
Tucson Electric Power Company	11	31	8	5	13	18	25	36	35	16	19.8	26
Virginia Electric and Power Company	12	20	26	16	21	6	10	17	26	2	15.6	8
Westar Energy (KPL)	18	21	14	30	17	18	37	25			22.5	33

Regional Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*2*	*6*	*5*	*2*	*3*	*3*	*7*	*5*	*2*	*8*	*4.3*	*3*
El Paso Electric Company	7	5	3	4	8	1	4	1	4	2	3.9	2
Nevada Power Company	3	2	6	1	1	6	6	8	6	6	4.5	4
PacifiCorp	8	7	8	7	9	9	3	6	1	5	6.3	9
Public Service Company of New Mexico	6	8	1	5	6	4	9	3	7	3	5.2	7
Southern California Edison Co.	5	1	2	8	4	2	1	2	5	1	3.1	1
Southwestern Public Service Company	9	3	9	6	7	6	2	4	3	6	5.5	8
Tucson Electric Power Company	4	4	4	3	5	6	5	7	8	4	5.0	6
Salt River Project	1		7		2	5	8				4.6	5

Situational Assessment Rankings - 2001

(a rank of 1 indicates the most challenged performer for each metric)

Base Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*4*	*31*	*12*	*2*	*2*	*9*	*18*	*33*	*4*	*31*	*14.6*	*6*
Alabama Power Company	24	22	34	22	33	15	24	31	11		24.0	36
Appalachian Power Company	8	5	21	23	29	18	34	30	8	12	18.8	19
Carolina Power & Light Company	16	25	27	6	31	6	29	9	20		18.8	18
Columbus Southern Power Company	10	4	10	15	12	18	36	25	28	9	16.7	10
Dayton Power and Light Company	20	19	16	28	34	18	17	11	24	15	20.2	26
Detroit Edison Company	30	6	5	27	35	16	10	20	34	26	20.9	29
Duke Energy Carolinas, LLC	26	8	32	5	36	5	12	21	14	26	18.5	14
Duke Energy Indiana, Inc.	29	34	33	17	14	18	13	23	23	5	20.9	29
El Paso Electric Company	33	35	4	16	15	2	16	1	7	3	13.2	3
Entergy Arkansas, Inc.	13	30	19	33	13	1	15	16	3	9	15.2	7
Entergy Louisiana, LLC												
Entergy Mississippi, Inc.	7	12	22	26	21	18	4	36	9	31	18.6	15
Florida Power & Light Company	1	2	6	10	7	10	8	3	33		8.9	2
Florida Power Corporation	2	16	9	3	10	14	28	4	30	22	13.8	4
Georgia Power Company	35	10	35	11	19	13	23	28	19	30	22.3	33
Gulf Power Company	3	21	14	14	8	18	21	27	10	22	15.8	9
Idaho Power Co.	22	24	29	7	37	18	6	32	1	22	19.8	24
Indiana Michigan Power Company	31	11	26	36	27	3	35	6	22	4	20.1	25
Indianapolis Power & Light Company	21	13	25	21	24	18	25	10	36	14	20.7	28
Kansas City Power & Light Company	17	7	17	12	23	11	22	29	16	33	18.7	16
Kansas Gas and Electric Company	27	17	20	30	26	8	2	37		19	20.7	27
KCP&L Greater Missouri Operations Company	6	23	7	25	20	18	7	19	27	19	17.1	11
Kentucky Utilities Company	19	27	30	20	18	18	20	8	17	6	18.3	13
Monongahela Power Company	36	20	18	32	4	18	26	12	6	15	18.7	16
Nevada Power Company	5	9	15	1	1	18	33	38	25	26	17.1	11
Ohio Power Company	37	14	36	35	38	18	37	13	18	19	26.5	38
Oklahoma Gas and Electric Company	15	15	28	37	16	18	9	5	29	22	19.4	23
PacifiCorp	34	33	23	18	30	38	11	34	2	18	24.1	37
Portland General Electric Company	11	37	11	24	28	18	27	14	31	13	21.4	31
Public Service Company of New Hampshire	14	38	1	19	3	17	30	7	13		15.8	8
Public Service Company of New Mexico	28	36	3	9	9	12	32	22	32	9	19.2	21
Public Service Company of Oklahoma	18	3	31	34	5	18	38	18	21	6	19.2	21
Southern California Edison Co.	25	1	2	4	32	4	1	2	15	1	8.7	1
Southwestern Electric Power Company	32	28	37	29	25	18	14	15	12	8	21.8	32
Southwestern Public Service Company	38	29	38	38	6	18	5	26	5	26	22.9	34
Tucson Electric Power Company	9	32	8	8	11	18	19	35	35	15	19.0	20
Virginia Electric and Power Company	12	18	24	13	17	7	3	17	26	2	13.9	5
Westar Energy (KPL)	23	26	13	31	22	18	31	24			23.5	35

Regional Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*2*	*4*	*5*	*2*	*2*	*3*	*5*	*5*	*2*	*8*	*3.8*	*2*
El Paso Electric Company	7	7	3	6	7	1	4	1	4	2	4.2	3
Nevada Power Company	3	2	6	1	1	5	9	8	6	6	4.7	5
PacifiCorp	8	6	8	7	8	8	3	6	1	5	6.0	9
Public Service Company of New Mexico	6	8	2	5	5	4	8	3	7	3	5.1	6
Southern California Edison Co.	5	1	1	3	9	2	1	2	5	1	3.0	1
Southwestern Public Service Company	9	3	9	8	4	5	2	4	3	6	5.3	7
Tucson Electric Power Company	4	5	4	4	6	5	6	7	8	4	5.3	7
Salt River Project	1		7		3		7				4.5	4

Situational Assessment Rankings - 2002

(a rank of 1 indicates the most challenged performer for each metric)

Base Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*4*	*20*	*11*	*2*	*7*	*8*	*20*	*33*	*4*	*31*	*14.0*	*6*
Alabama Power Company	24	22	36	30	19	16	28	32	11		24.2	36
Appalachian Power Company	8	37	22	31	23	17	15	28	8	13	20.2	24
Carolina Power & Light Company	14	18	28	5	20	6	34	8	20		17.0	12
Columbus Southern Power Company	9	38	12	16	4	17	26	24	28	10	18.4	17
Dayton Power and Light Company	17	19	17	35	28	17	18	11	24	16	20.2	24
Detroit Edison Company	25	3	6	33	34	15	10	19	34	26	20.5	26
Duke Energy Carolinas, LLC	27	4	31	18	30	5	9	22	14	26	18.6	18
Duke Energy Indiana, Inc.	31	34	34	17	10	17	8	30	23	5	20.9	30
El Paso Electric Company	33	29	4	10	16	1	11	1	7	3	11.5	2
Entergy Arkansas, Inc.	15	27	18	37	18	2	6	15	3	10	15.1	9
Entergy Louisiana, LLC												
Entergy Mississippi, Inc.	7	9	23	25	24	17	36	36	9	32	21.8	31
Florida Power & Light Company	1	2	7	6	3	11	7	3	33		8.1	1
Florida Power Corporation	2	10	9	7	5	14	14	5	30	24	12.0	4
Georgia Power Company	34	5	35	9	14	13	35	29	19	29	22.2	32
Gulf Power Company	3	14	15	11	2	17	24	27	10	16	13.9	5
Idaho Power Co.	23	8	24	4	37	17	4	31	1	24	17.3	13
Indiana Michigan Power Company	32	36	30	34	15	4	25	4	22	4	20.6	28
Indianapolis Power & Light Company	22	6	25	22	17	17	19	12	36	15	19.1	19
Kansas City Power & Light Company	16	12	16	15	27	12	27	26	16	33	20.0	23
Kansas Gas and Electric Company	28	13	20	27	29	9	1	37		21	20.6	27
KCP&L Greater Missouri Operations Company	10	17	8	14	12	17	3	20	27	21	14.9	8
Kentucky Utilities Company	18	28	32	20	8	17	22	9	18	7	17.9	15
Monongahela Power Company	36	16	19	29	6	17	21	14	6	16	18.0	16
Nevada Power Company	5	30	13	1	1	17	33	38	25	29	19.2	20
Ohio Power Company	37	35	37	36	38	17	38	16	17	21	29.2	38
Oklahoma Gas and Electric Company	20	11	26	24	25	17	5	6	29	5	16.8	11
PacifiCorp	35	21	21	19	35	38	17	34	2	20	24.2	35
Portland General Electric Company	12	26	10	23	33	17	32	10	31	14	20.8	29
Public Service Company of New Hampshire	13	31	1	13	13	17	31	7	13		15.4	10
Public Service Company of New Mexico	30	33	3	12	11	10	30	21	32	10	19.2	20
Public Service Company of Oklahoma	19	7	27	32	26	17	2	18	21	7	17.6	14
Southern California Edison Co.	29	1	2	21	32	3	13	2	15	1	11.9	3
Southwestern Electric Power Company	26	23	33	26	36	17	29	13	12	9	22.4	33
Southwestern Public Service Company	38	25	38	38	22	17	23	23	5	26	25.5	37
Tucson Electric Power Company	6	32	5	3	31	17	12	35	35	16	19.2	20
Virginia Electric and Power Company	11	15	29	8	9	7	16	17	26	2	14.0	6
Westar Energy (KPL)	21	24	14	28	21	17	37	25			23.4	34

Regional Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*2*	*2*	*5*	*2*	*2*	*3*	*5*	*5*	*2*	*8*	*3.6*	*3*
El Paso Electric Company	7	5	3	4	5	1	1	1	4	2	3.3	1
Nevada Power Company	3	6	6	1	1	5	9	8	6	7	5.2	7
PacifiCorp	8	3	8	6	9	8	4	6	1	5	5.8	8
Public Service Company of New Mexico	6	8	2	5	4	4	7	3	7	3	4.9	5
Southern California Edison Co.	5	1	1	7	8	2	3	2	5	1	3.5	2
Southwestern Public Service Company	9	4	9	8	6	5	6	4	3	6	6.0	9
Tucson Electric Power Company	4	7	4	3	7	5	2	7	8	4	5.1	6
Salt River Project	1		7		3		8				4.8	4

Situational Assessment Rankings - 2003

(a rank of 1 indicates the most challenged performer for each metric)

Base Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*4*	*6*	*12*	*2*	*3*	*7*	*35*	*33*	*4*	*30*	*13.6*	*5*
Alabama Power Company	29	22	36	26	20	14	26	32	11		24.0	34
Appalachian Power Company	7	25	21	32	29	17	19	29	8	12	19.9	22
Carolina Power & Light Company	14	19	27	11	27	6	31	13	21		18.8	18
Columbus Southern Power Company	10	21	11	19	12	17	18	23	28	10	16.9	12
Dayton Power and Light Company	17	20	16	33	31		17	12	24	15	20.6	25
Detroit Edison Company	19	8	5	36	38	15	12	18	34	25	21.0	28
Duke Energy Carolinas, LLC	27	3	31	37	33	5	14	21	13	25	20.9	27
Duke Energy Indiana, Inc.	31	38	33	22	14	17	4	31	23	5	21.8	32
El Paso Electric Company	33	33	4	7	10	2	11	1	7	3	11.1	3
Entergy Arkansas, Inc.	15	29	18	12	21	1	16	26	3	10	15.1	8
Entergy Louisiana, LLC												
Entergy Mississippi, Inc.	8	7	24	23	25	17	6	37	9	31	18.7	17
Florida Power & Light Company	1	2	8	5	2	11	7	5	33		8.2	1
Florida Power Corporation	2	11	10	6	4	16	13	10	30	22	12.4	4
Georgia Power Company	35	10	35	10	19	12	34	28	20	28	23.1	33
Gulf Power Company	3	17	15	9	6	17	28	22	10	15	14.2	7
Idaho Power Co.	23	9	22	3	36	17	3	34	1	22	17.0	13
Indiana Michigan Power Company	32	36	26	29	32	4	15	3	22	4	20.3	24
Indianapolis Power & Light Company	20	5	25	20	23	17	21	7	36	14	18.8	19
Kansas City Power & Light Company	16	18	17	17	24	13	30	17	16	33	20.1	23
Kansas Gas and Electric Company	30	24	20	27	28	9	1	36		19	21.6	30
KCP&L Greater Missouri Operations Company	9	15	7	15	8	17	5	16	27	19	13.8	6
Kentucky Utilities Company	22	23	32	25	11	17	22	14	18	7	19.1	20
Monongahela Power Company	36	13	19	31	9	17	23	9	6	15	17.8	16
Nevada Power Company	5	16	14	1	1	17	27	38	25	28	17.2	14
Ohio Power Company	37	34	37	35	37	17	33	25	17	19	29.1	38
Oklahoma Gas and Electric Company	18	12	28	21	18	17	9	4	29	5	16.1	10
PacifiCorp	34	32	23	13	26	37	24	30	2	24	24.5	35
Portland General Electric Company	11	31	9	24	35	17	29	6	31	13	20.6	26
Public Service Company of New Hampshire	12	37	1	16	5	17	32	11	14		16.1	11
Public Service Company of New Mexico	28	35	3	4	13	10	36	24	32	31	21.6	31
Public Service Company of Oklahoma	21	4	30	38	22	17	25	15	19	7	19.8	21
Southern California Edison Co.	25	1	2	18	16	3	2	2	15	1	8.5	2
Southwestern Electric Power Company	26	30	34	30	34	17	10	8	12	9	21.0	28
Southwestern Public Service Company	38	28	38	28	15	17	37	20	5	25	25.1	36
Tucson Electric Power Company	6	27	6	8	17	17	8	35	35	15	17.4	15
Virginia Electric and Power Company	13	14	29	14	7	8	20	27	26	2	16.0	9
Westar Energy (KPL)	24	26	13	34	30	17	38	19			25.1	37

Regional Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*2*	*2*	*5*	*2*	*2*	*3*	*7*	*6*	*2*	*7*	*3.8*	*3*
El Paso Electric Company	7	7	3	4	4	1	3	1	4	2	3.6	2
Nevada Power Company	3	3	6	1	1	5	5	8	6	6	4.4	5
PacifiCorp	8	6	8	6	9	8	4	5	1	4	5.9	8
Public Service Company of New Mexico	6	8	2	3	5	4	8	4	7	8	5.5	7
Southern California Edison Co.	5	1	1	7	7	2	1	2	5	1	3.2	1
Southwestern Public Service Company	9	5	9	8	6	5	9	3	3	5	6.2	9
Tucson Electric Power Company	4	4	4	5	8	5	2	7	8	3	5.0	6
Salt River Project	1		7		3		6				4.3	4

Situational Assessment Rankings - 2004

(a rank of 1 indicates the most challenged performer for each metric)

Base Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*4*	*26*	*13*	*3*	*2*	*8*	*36*	*33*	*4*	*31*	*16.0*	*8*
Alabama Power Company	29	24	37	24	10	14	27	32	11		23.1	34
Appalachian Power Company	8	38	24	34	21	17	30	31	8	12	22.3	31
Carolina Power & Light Company	15	20	28	14	13	6	31	12	21		17.8	14
Columbus Southern Power Company	10	31	11	20	20	17	16	21	28	10	18.4	18
Dayton Power and Light Company	17	25	17	37	32	17	15	10	23	16	20.9	26
Detroit Edison Company	14	8	4	36	38	16	8	20	34	5	18.3	17
Duke Energy Carolinas, LLC	25	5	31	15	29	5	14	26	13	26	18.9	20
Duke Energy Indiana, Inc.	31	29	34	32	17	17	18	28	24	6	23.6	35
El Paso Electric Company	32	28	5	6	9	2	10	1	7	3	10.3	3
Entergy Arkansas, Inc.	16	30	18	28	26	1	13	22	3	10	16.7	12
Entergy Louisiana, LLC												
Entergy Mississippi, Inc.	9	2	23	19	27	17	4	37	9	32	17.9	15
Florida Power & Light Company	1	1	8	7	5	11	7	9	33		9.1	1
Florida Power Corporation	2	11	10	8	7	15	11	11	30	24	12.9	5
Georgia Power Company	34	12	35	12	11	13	34	29	20	29	22.9	33
Gulf Power Company	3	22	15	11	6	17	26	25	10	16	15.1	7
Idaho Power Co.	19	6	21	4	35	17	3	34	1	24	16.4	10
Indiana Michigan Power Company	33	35	27	33	31	3	25	3	22	4	21.6	27
Indianapolis Power & Light Company	20	4	25	22	23	17	21	7	36	14	18.9	20
Kansas City Power & Light Company	18	18	16	27	30	12	32	15	16	34	21.8	29
Kansas Gas and Electric Company	30	17	19	29	25	9	1	36		21	20.8	25
KCP&L Greater Missouri Operations Company	11	9	9	18	15	17	5	19	27	16	14.6	6
Kentucky Utilities Company	22	21	32	23	8	17	22	14	18	26	20.3	23
Monongahela Power Company	36	13	20	35	16	17	19	6	6	16	18.4	18
Nevada Power Company	5	10	14	1	1	17	24	38	25	29	16.4	10
Ohio Power Company	37	36	36	30	36	17	29	24	17	21	28.3	38
Oklahoma Gas and Electric Company	21	15	26	25	28	17	6	8	29	6	18.1	16
PacifiCorp	35	33	22	13	24	38	12	30	2	15	22.4	32
Portland General Electric Company	6	34	7	17	37	17	28	5	31	13	19.5	22
Public Service Company of New Hampshire	12	3	1	2	3	17	17	16	14	21	10.6	4
Public Service Company of New Mexico	24	37	3	5	19	10	33	23	32	32	21.8	29
Public Service Company of Oklahoma	27	14	30	31	22	17	23	13	19	8	20.4	24
Southern California Edison Co.	26	7	2	21	14	4	2	2	15	1	9.4	2
Southwestern Electric Power Company	28	19	33	26	33	17	35	4	12	9	21.6	27
Southwestern Public Service Company	38	32	38	9	18	17	38	18	5	26	23.9	36
Tucson Electric Power Company	7	23	6	10	12	17	9	35	35	16	17.0	13
Virginia Electric and Power Company	13	16	29	16	4	7	20	27	26	2	16.0	8
Westar Energy (KPL)	23	27	12	38	34	17	37	17			25.6	37

Regional Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*2*	*4*	*5*	*2*	*2*	*3*	*8*	*6*	*2*	*7*	*4.1*	*3*
El Paso Electric Company	7	5	3	4	3	1	3	1	4	2	3.3	1
Nevada Power Company	3	2	6	1	1	5	5	8	6	6	4.3	4
PacifiCorp	8	7	8	7	9	8	4	5	1	3	6.0	8
Public Service Company of New Mexico	5	8	2	3	8	4	7	4	7	8	5.6	7
Southern California Edison Co.	6	1	1	8	6	2	1	2	5	1	3.3	1
Southwestern Public Service Company	9	6	9	5	7	5	9	3	3	5	6.1	9
Tucson Electric Power Company	4	3	4	6	5	5	2	7	8	4	4.8	6
Salt River Project	1		7		4		6				4.5	5

Situational Assessment Rankings - 2005

(a rank of 1 indicates the most challenged performer for each metric)

Base Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*4*	*38*	*13*	*2*	*2*	*9*	*35*	*36*	*4*	*2*	*14.5*	*6*
Alabama Power Company	29	23	36	25	11	13	34	31	11		23.7	35
Appalachian Power Company	8	1	25	30	19	17	16	35	8	11	17.0	12
Carolina Power & Light Company	14	19	24	10	27	6	33	10	22		18.3	16
Columbus Southern Power Company	9	28	11	29	21	17	24	26	27	9	20.1	27
Dayton Power and Light Company	17	22	17	33	32	17	15	8	23	15	19.9	25
Detroit Edison Company	15	14	5	35	37	15	17	18	34	6	19.6	23
Duke Energy Carolinas, LLC	26	7	30	11	33	5	10	24	13	26	18.5	17
Duke Energy Indiana, Inc.	31	33	34	18	8	17	1	28	24	7	20.1	27
El Paso Electric Company	32	31	4	5	26	3	4	1	7	3	11.6	2
Entergy Arkansas, Inc.	16	34	21	32	9	1	11	22	3	9	15.8	8
Entergy Louisiana, LLC												
Entergy Mississippi, Inc.	10	6	22	31	30	17	3	37	9	32	19.7	24
Florida Power & Light Company	1	4	8	7	6	11	6	12	33		9.8	1
Florida Power Corporation	2	17	10	8	12	16	20	13	30	24	15.2	7
Georgia Power Company	35	10	33	13	23	14	38	27	20	30	24.3	36
Gulf Power Company	3	29	15	19	16	17	30	25	10	15	17.9	14
Idaho Power Co.	19	16	16	3	36	17	8	32	1	24	17.2	13
Indiana Michigan Power Company	33	36	28	36	29	2	27	2	21	4	21.8	32
Indianapolis Power & Light Company	20	9	26	28	18	17	23	5	36	13	19.5	22
Kansas City Power & Light Company	18	27	18	26	15	12	28	15	16	34	20.9	30
Kansas Gas and Electric Company	30	20	23	24	14	8	2	34		20	19.4	21
KCP&L Greater Missouri Operations Company	11	12	9	15	3	17	5	20	28	15	13.5	5
Kentucky Utilities Company	23	25	32	23	5	17	19	11	18	26	19.9	25
Monongahela Power Company	34	8	19	34	31	17	13	4	6	15	18.1	15
Nevada Power Company	5	5	12	1	1	17	31	38	25	30	16.5	9
Ohio Power Company	37	35	37	37	17	17	32	29	17	20	27.8	38
Oklahoma Gas and Electric Company	22	13	27	21	20	17	7	9	29	26	19.1	20
PacifiCorp	36	18	20	9	34	38	12	30	2	23	22.2	33
Portland General Electric Company	6	26	6	14	38	17	29	7	31	12	18.6	18
Public Service Company of New Hampshire	12	2	1	16	7	17	22	19	14	20	13.0	4
Public Service Company of New Mexico	24	37	3	4	25	10	18	21	32	32	20.6	29
Public Service Company of Oklahoma	25	3	31	27	13	17	37	14	19	4	19.0	19
Southern California Edison Co.	27	11	2	17	22	4	21	3	15	1	12.3	3
Southwestern Electric Power Company	28	24	35	20	24	17	36	6	12	8	21.0	31
Southwestern Public Service Company	38	32	38	38	28	17	9	17	5	26	24.8	37
Tucson Electric Power Company	7	21	7	6	10	17	14	33	35	15	16.5	9
Virginia Electric and Power Company	13	15	29	12	4	7	26	23	26	13	16.8	11
Westar Energy (KPL)	21	30	14	22	35	17	25	16			22.5	34

Regional Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*2*	*8*	*6*	*2*	*2*	*3*	*9*	*7*	*2*	*2*	*4.3*	*3*
El Paso Electric Company	7	5	3	4	7	1	1	1	4	3	3.6	1
Nevada Power Company	3	1	5	1	1	5	7	8	6	7	4.4	4
PacifiCorp	8	3	8	6	9	8	3	5	1	5	5.6	8
Public Service Company of New Mexico	5	7	2	3	6	4	5	4	7	8	5.1	7
Southern California Edison Co.	6	2	1	7	5	2	6	2	5	1	3.7	2
Southwestern Public Service Company	9	6	9	8	8	5	2	3	3	6	5.9	9
Tucson Electric Power Company	4	4	4	5	3	5	4	6	8	4	4.7	5
Salt River Project	1		7		4		8				5.0	6

Situational Assessment Rankings - 2006

(a rank of 1 indicates the most challenged performer for each metric)

Base Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*4*	*36*	*13*	*3*	*2*	*10*	*17*	*35*	*4*	*1*	*12.5*	*4*
Alabama Power Company	28	24	37	28	13	14	32	30	11		24.1	35
Appalachian Power Company	14	33	30	32	3	18	12	37	8	7	19.4	23
Carolina Power & Light Company	12	26	20	11	33	7	35	7	22		19.2	22
Columbus Southern Power Company	13	28	11	4	5	18	27	26	29	9	17.0	12
Dayton Power and Light Company	18	19	17	34	36	18	16	9	24	15	20.6	27
Detroit Edison Company	27	11	5	33	24	17	10	20	35	30	21.2	28
Duke Energy Carolinas, LLC	26	7	29	14	31	6	11	25	13	25	18.7	17
Duke Energy Indiana, Inc.	36	35	35	30	26	18	36	29	25	6	27.6	38
El Paso Electric Company	34	29	4	8	19	4	7	1	7	2	11.5	3
Entergy Arkansas, Inc.	17	25	21	23	10	1	22	19	3	9	15.0	6
Entergy Louisiana, LLC	31	1	38			3	20	28	21		20.3	26
Entergy Mississippi, Inc.	8	6	23	20	27	18	2	38	9	33	18.4	15
Florida Power & Light Company	1	2	7	13	15	11	3	11	34		10.8	2
Florida Power Corporation	2	17	9	9	22	16	23	14	31	24	16.7	11
Georgia Power Company	33	14	34	1	4	15	37	27	23	30	21.8	31
Gulf Power Company	3	22	15	7	20	18	29	24	10	15	16.3	9
Idaho Power Co.	15	12	19	5	14	18	9	34	1	25	15.2	7
Indiana Michigan Power Company	35	38	26	35	32	5	31	2	20	3	22.7	34
Indianapolis Power & Light Company	22	5	24	31	34	18	38	4	37	12	22.5	33
Kansas City Power & Light Company	16	20	18	27	17	13	30	16	16	12	18.5	16
Kansas Gas and Electric Company	32	21	25	24	8	9	1	31		20	19.0	20
KCP&L Greater Missouri Operations Company	9	10	10	18	7	18	5	18	28	15	13.8	5
Kentucky Utilities Company	24	30	32	22	23	18	15	12	18	25	21.9	32
Monongahela Power Company	30	9	16	38	38	18	8	3	6	15	18.1	14
Nevada Power Company	5	4	12	2	1	18	25	39	26	30	16.2	8
Ohio Power Company	38	37	33	36	37	18	21	36	17	20	29.3	39
Oklahoma Gas and Electric Company	20	15	28	19	18	18	4	10	30	25	18.7	17
PacifiCorp	37	18	22	10	11	39	6	33	2	23	20.1	25
Portland General Electric Company	6	32	6	16	35	18	34	6	32	11	19.6	24
Public Service Company of New Hampshire	10	3	1	21	29	18	26	22	14	20	16.4	10
Public Service Company of New Mexico	21	39	2	6	12	12	33	21	33	33	21.2	28
Public Service Company of Oklahoma	25	8	31	29	21	18	18	15	19	3	18.7	17
Southern California Edison Co.	23	13	3	17	9	2	14	5	15	5	10.6	1
Southwestern Electric Power Company	29	27	36	25	28	18	24	8	12	7	21.4	30
Southwestern Public Service Company	39	34	39	37	16	18	19	13	5	25	24.5	37
Tucson Electric Power Company	7	23	8	12	6	18	13	32	36	15	17.0	12
Virginia Electric and Power Company	11	16	27	15	25	8	28	23	27	12	19.2	21
Westar Energy (KPL)	19	31	14	26	30	18	39	17			24.3	36

Regional Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*2*	*7*	*6*	*2*	*2*	*3*	*5*	*7*	*2*	*1*	*3.7*	*1*
El Paso Electric Company	7	5	3	4	9	2	2	1	4	2	3.9	3
Nevada Power Company	3	1	5	1	1	5	7	8	6	7	4.4	4
PacifiCorp	8	3	8	5	6	8	1	6	1	5	5.1	7
Public Service Company of New Mexico	5	8	1	3	7	4	8	4	7	8	5.5	8
Southern California Edison Co.	6	2	2	7	5	1	4	2	5	3	3.7	1
Southwestern Public Service Company	9	6	9	8	8	5	6	3	3	6	6.3	9
Tucson Electric Power Company	4	4	4	6	4	5	3	5	8	4	4.7	5
Salt River Project	1		7		3		9				5.0	6

Situational Assessment Rankings - 2007

(a rank of 1 indicates the most challenged performer for each metric)

Base Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*4*	*34*	*12*	*2*	*3*	*10*	*11*	*35*	*5*	*1*	*11.7*	*2*
Alabama Power Company	26	25	37	19	22	14	22	29	10		22.7	35
Appalachian Power Company	13	33	31	31	5	18	21	36	8	25	22.1	33
Carolina Power & Light Company	11	22	21	10	31	7	32	4	22		17.8	14
Columbus Southern Power Company	20	23	16	30	2	18	27	23	29	7	19.5	20
Dayton Power and Light Company	14	24	17	37	33	18	14	8	24	17	20.6	27
Detroit Edison Company	28	8	7	38	9	17	20	19	33	31	21.0	29
Duke Energy Carolinas, LLC	22	3	29	9	27	6	15	16	13	26	16.6	8
Duke Energy Indiana, Inc.	32	20	35	23	16	18	37	28	25	4	23.8	37
El Paso Electric Company	31	31	4	7	15	4	17	1	7	8	12.5	4
Entergy Arkansas, Inc.	15	32	20	32	20	2	10	14	3	10	15.8	5
Entergy Louisiana, LLC	36	6	38	24	34	5	18	13	21		21.7	31
Entergy Mississippi, Inc.	9	5	22	26	32	18	2	38	9	33	19.4	19
Florida Power & Light Company	1	1	8	11	21	13	5	12	34		11.8	3
Florida Power Corporation	2	14	9	29	35	16	19	21	31	23	19.9	24
Georgia Power Company	34	15	33	13	7	15	25	27	23	26	21.8	32
Gulf Power Company	3	27	13	3	28	18	29	24	11	17	17.3	10
Idaho Power Co.	16	30	18	5	8	18	3	34	1	26	15.9	6
Indiana Michigan Power Company	33	39	27	35	29	3	31	2	20	2	22.1	33
Indianapolis Power & Light Company	18	7	25	34	23	18	36	3	37	10	21.1	30
Kansas City Power & Light Company	17	19	19	33	12	12	26	15	16	17	18.6	17
Kansas Gas and Electric Company	35	9	24	27	11	9	1	31		21	18.7	18
KCP&L Greater Missouri Operations Company	8	16	6	20	38	18	6	26	28	10	17.6	12
Kentucky Utilities Company	21	21	32	22	13	18	13	22	18	26	20.6	27
Monongahela Power Company	29	17	15	25	39	18	9	5	6	10	17.3	10
Nevada Power Company	6	2	11	4	4	18	28	39	27	26	16.5	7
Ohio Power Company	38	38	36	36	36	18	24	37	17	21	30.1	39
Oklahoma Gas and Electric Company	23	12	26	18	25	18	7	9	30	31	19.9	24
PacifiCorp	37	18	23	8	10	18	8	33	2	23	18.0	15
Portland General Electric Company	5	36	5	14	37	18	33	7	32	10	19.7	23
Public Service Company of New Hampshire	10	10	1	28	30	18	23	25	14	8	16.7	9
Public Service Company of New Mexico	24	37	3	1	1	11	38	18	35	33	20.1	26
Public Service Company of Oklahoma	27	11	30	21	26	18	16	17	19	10	19.5	20
Southern California Edison Co.	25	4	2	17	19	1	4	6	15	3	9.6	1
Southwestern Electric Power Company	30	26	34	6	18	18	34	11	12	6	19.5	20
Southwestern Public Service Company	39	35	39	39	24	18	30	10	4	5	24.3	38
Tucson Electric Power Company	7	29	10	12	6	18	12	30	36	17	17.7	13
Virginia Electric and Power Company	12	13	28	15	14	8	35	20	26	10	18.1	16
Westar Energy (KPL)	19	28	14	16	17	18	39	32			22.9	36

Regional Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*2*	*6*	*6*	*2*	*3*	*3*	*3*	*7*	*3*	*1*	*3.6*	*2*
El Paso Electric Company	7	5	3	4	7	2	5	1	4	4	4.2	3
Nevada Power Company	3	1	5	3	4	5	6	8	6	7	4.8	5
PacifiCorp	8	3	8	5	6	5	2	6	1	6	5.0	7
Public Service Company of New Mexico	5	8	2	1	1	4	9	4	7	8	4.9	6
Southern California Edison Co.	6	2	1	7	8	1	1	2	5	2	3.5	1
Southwestern Public Service Company	9	7	9	8	9	5	7	3	2	3	6.2	9
Tucson Electric Power Company	4	4	4	6	5	5	4	5	8	5	5.0	7
Salt River Project	1		7		2		8				4.5	4

Situational Assessment Rankings - 2008

(a rank of 1 indicates the most challenged performer for each metric)

Base Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*3*	*12*	*11*	*6*	*7*	*10*	*10*	*32*	*5*	*1*	*9.7*	*1*
Alabama Power Company	27	22	36	18	32	14	26	22	11		23.1	36
Appalachian Power Company	14	33	31	20	3	18	19	37	8	33	21.6	32
Carolina Power & Light Company	11	26	20	3	28	7	32	3	22		16.9	11
Columbus Southern Power Company	25	30	17	33	1	18	31	21	29	9	21.4	29
Dayton Power and Light Company	13	23	16	35	31	18	13	7	24	19	19.9	24
Detroit Edison Company	31	10	6	38	10	15	14	15	33	1	17.3	12
Duke Energy Carolinas, LLC	19	4	27	5	26	6	12	14	14	27	15.4	6
Duke Energy Indiana, Inc.	30	25	35	31	29	18	36	23	25	6	25.8	38
El Paso Electric Company	33	34	4	2	11	3	24	1	7	11	13.0	3
Entergy Arkansas, Inc.	15	28	22	25	22	2	21	11	3	13	16.2	9
Entergy Louisiana, LLC	36	5	38	14	30	5	22	13	21		20.4	26
Entergy Mississippi, Inc.	8	11	21	29	34	18	4	38	9	34	20.6	27
Florida Power & Light Company	1	1	8	32	27	12	6	10	34		14.6	4
Florida Power Corporation	2	19	9	27	35	17	23	26	31	26	21.5	30
Georgia Power Company	34	16	33	15	13	16	20	24	23	27	22.1	34
Gulf Power Company	4	29	14	28	19	18	28	28	10	19	19.7	22
Idaho Power Co.	16	15	19	4	8	18	3	30	2	31	14.6	5
Indiana Michigan Power Company	32	38	26	34	33	4	27	4	20	3	22.1	34
Indianapolis Power & Light Company	17	7	25	37	25	18	34	2	37	13	21.5	30
Kansas City Power & Light Company	18	24	18	24	16	13	30	19	16	19	19.7	22
Kansas Gas and Electric Company	35	8	23	17	15	9	1	31		22	17.9	15
KCP&L Greater Missouri Operations Company	6	13	7			18	9	34	26	13	15.8	8
Kentucky Utilities Company	20	21	32	23	17	18	16	27	18	27	21.9	33
Monongahela Power Company	28	9	15	19	38	18	2	8	6	13	15.6	7
Nevada Power Company	7	2	12	11	5	18	38	39	28	27	18.7	19
Ohio Power Company	38	37	37	36	23	18	18	36	17	22	28.2	39
Oklahoma Gas and Electric Company	21	17	29	12	12	18	11	12	30	31	19.3	21
PacifiCorp	37	20	24	8	6	18	8	35	1	25	18.2	17
Portland General Electric Company	5	35	5	7	37	18	29	5	32	13	18.6	18
Public Service Company of New Hampshire	10	3	1	30	36	18	17	29	13	11	16.8	10
Public Service Company of New Mexico	22	39	3	9	2	11	33	17	35	7	17.8	14
Public Service Company of Oklahoma	26	14	30	21	24	18	7	18	19	13	19.0	20
Southern California Edison Co.	24	6	2	26	14	1	5	6	15	4	10.3	2
Southwestern Electric Power Company	29	27	34	13	20	18	35	16	12	8	21.2	28
Southwestern Public Service Company	39	32	39	1	4	18	25	9	4	9	18.0	16
Tucson Electric Power Company	9	31	10	16	9	18	15	25	36	4	17.3	12
Virginia Electric and Power Company	12	18	28	10	18	8	37	20	27	22	20.0	25
Westar Energy (KPL)	23	36	13	22	21	18	39	33			25.6	37

Regional Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*2*	*3*	*5*	*3*	*6*	*3*	*3*	*6*	*3*	*1*	*3.5*	*1*
El Paso Electric Company	7	7	3	2	8	2	5	1	4	6	4.5	4
Nevada Power Company	3	1	6	6	4	5	9	8	6	8	5.6	9
PacifiCorp	8	4	8	4	5	5	2	7	1	7	5.1	7
Public Service Company of New Mexico	5	8	2	5	1	4	8	4	7	4	4.8	5
Southern California Edison Co.	6	2	1	8	9	1	1	2	5	2	3.7	2
Southwestern Public Service Company	9	6	9	1	3	5	6	3	2	5	4.9	6
Tucson Electric Power Company	4	5	4	7	7	5	4	5	8	2	5.1	7
Salt River Project	1		7		2		7				4.3	3

Situational Assessment Rankings - 2009

(a rank of 1 indicates the most challenged performer for each metric)

Base Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*4*	*14*	*11*	*15*	*8*	*10*	*17*	*28*	*5*	*1*	*11.3*	*2*
Alabama Power Company	23	25	37	28	34	15	29	22	11		24.9	37
Appalachian Power Company	10	35	28	24	29	18	15	34	8	20	22.1	34
Carolina Power & Light Company	11	24	22	3	18	6	33	3	22		15.8	9
Columbus Southern Power Company	26	30	17	22	4	18	30	20	29	6	20.2	27
Dayton Power and Light Company	15	20	16	30	37	18	4	39	25	13	21.7	32
Detroit Edison Company	30	13	5	38	32	16	16	10	33	2	19.5	22
Duke Energy Carolinas, LLC	17	10	27	17	23	5	20	15	14	26	17.4	13
Duke Energy Indiana, Inc.	31	29	32	31	35	18	34	24	26	4	26.4	38
El Paso Electric Company	32	37	4	2	3	2	25	2	7	26	14.0	5
Entergy Arkansas, Inc.	16	28	20	23	28	1	22	5	3	9	15.5	7
Entergy Louisiana, LLC	36	6	38	18	9	4	23	12	21		18.6	19
Entergy Mississippi, Inc.	7	9	21	20	27	18	3	36	9	34	18.4	17
Florida Power & Light Company	1	1	7	35	12	12	6	11	34		13.2	3
Florida Power Corporation	2	21	8	37	21	17	18	27	31	24	20.6	28
Georgia Power Company	35	15	35	19	14	14	24	29	24	26	23.5	35
Gulf Power Company	3	23	12	36	26	18	26	32	10	13	19.9	25
Idaho Power Co.	14	11	18	8	11	18	5	17	2	33	13.7	4
Indiana Michigan Power Company	33	39	25	32	33	8	14	4	20	6	21.4	30
Indianapolis Power & Light Company	19	5	24	33	31	18	36	1	37	9	21.3	29
Kansas City Power & Light Company	22	22	19	25	16	13	31	19	16	13	19.6	23
Kansas Gas and Electric Company	34	12	23	4	22	9	1	25		24	17.1	12
KCP&L Greater Missouri Operations Company	6	8	10			18	11	35	23	13	15.5	7
Kentucky Utilities Company	20	26	34	7	20	18	19	26	18	26	21.4	30
Monongahela Power Company	27	2	15	13	38	18	8	6	6	9	14.2	6
Nevada Power Company	8	3	13	26	5	18	35	38	28	26	20.0	26
Ohio Power Company	38	38	36	34	36	18	21	30	17	20	28.8	39
Oklahoma Gas and Electric Company	21	19	29	5	13	18	7	14	30	26	18.2	16
PacifiCorp	37	18	26	10	7	18	13	37	1	18	18.5	18
Portland General Electric Company	5	31	6	16	15	18	28	7	32	9	16.7	11
Public Service Company of New Hampshire	12	4	1	27	24	18	37	31	13	8	17.5	14
Public Service Company of New Mexico	18	36	3	29	2	11	10	13	35	20	17.7	15
Public Service Company of Oklahoma	24	16	30	12	25	18	12	16	19	26	19.8	24
Southern California Edison Co.	28	7	2	21	17	3	2	9	15	5	10.9	1
Southwestern Electric Power Company	29	27	33	11	30	18	27	18	12	13	21.8	33
Southwestern Public Service Company	39	32	39	1	1	18	32	8	4	19	19.3	20
Tucson Electric Power Company	9	33	9	14	6	18	9	23	36	3	16.0	10
Virginia Electric and Power Company	13	17	31	9	10	7	38	21	27	20	19.3	20
Westar Energy (KPL)	25	34	14	6	19	18	39	33			23.5	35

Regional Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*2*	*3*	*5*	*5*	*7*	*3*	*5*	*6*	*3*	*1*	*4.0*	*2*
El Paso Electric Company	7	8	3	2	3	1	6	1	4	7	4.2	3
Nevada Power Company	3	1	6	7	4	5	9	8	6	7	5.6	8
PacifiCorp	8	4	8	3	6	5	4	7	1	4	5.0	7
Public Service Company of New Mexico	5	7	2	8	2	4	3	4	7	6	4.8	6
Southern California Edison Co.	6	2	1	6	9	2	1	3	5	3	3.8	1
Southwestern Public Service Company	9	5	9	1	1	5	8	2	2	5	4.7	5
Tucson Electric Power Company	4	6	4	4	5	5	2	5	8	2	4.5	4
Salt River Project	1		7		8		7				5.8	9

Situational Assessment Rankings - 2010

(a rank of 1 indicates the most challenged performer for each metric)

Base Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*4*	*12*	*10*	*13*	*31*	*10*	*20*	*26*	*5*	*1*	*13.2*	*3*
Alabama Power Company	25	29	37	33	18	15	27	20	11		23.9	36
Appalachian Power Company	11	30	27	30	28	17	14	33	8	7	20.5	25
Carolina Power & Light Company	7	26	25	38	10	8	32	3	22		19.0	20
Columbus Southern Power Company	22	23	18	34	14	17	37	17	29	5	21.6	29
Dayton Power and Light Company	14	27	17	35	35	17	38	39	25	16	26.3	38
Detroit Edison Company	23	14	5	37	38	16	15	10	33	10	20.1	24
Duke Energy Carolinas, LLC	16	6	28	18	13	5	24	13	14	29	16.6	13
Duke Energy Indiana, Inc.	31	24	32	7	26	17	34	27	26	3	22.7	34
El Paso Electric Company	33	38	4	2	2	2	23	2	7	25	13.8	4
Entergy Arkansas, Inc.	15	34	23	15	7	1	8	5	3	20	13.1	1
Entergy Louisiana, LLC	36	4	38	10	1	4	25	9	21		16.4	12
Entergy Mississippi, Inc.	6	5	22	12	12	17	2	35	9	35	15.5	9
Florida Power & Light Company	1	2	8	21	21	12	13	12	34	7	13.1	1
Florida Power Corporation	2	15	9	11	23	17	3	28	31	10	14.9	7
Georgia Power Company	32	8	35	28	9	14	22	29	24	34	23.5	35
Gulf Power Company	3	17	12	23	22	17	28	30	10	16	17.8	17
Idaho Power Co.	21	19	15	17	36	17	6	21	1	29	18.2	18
Indiana Michigan Power Company	35	33	26	32	27	3	19	4	19	20	21.8	31
Indianapolis Power & Light Company	17	10	21	31	32	17	36	1	37	14	21.6	29
Kansas City Power & Light Company	19	25	19	26	17	13	30	15	16	10	19.0	20
Kansas Gas and Electric Company	34	9	24	22	16	9	1	25		25	18.3	19
KCP&L Greater Missouri Operations Company	5	3	13	29		17	5	32	23	16	15.9	11
Kentucky Utilities Company	27	20	33	9	8	17	11	38	18	24	20.5	25
Monongahela Power Company	29	1	16	19	30	17	10	6	6	14	14.8	6
Nevada Power Company	10	7	11	24	29	17	33	37	28	29	22.5	33
Ohio Power Company	38	39	36	36	34	17	26	23	17	20	28.6	39
Oklahoma Gas and Electric Company	24	21	30	5	6	17	9	19	30	29	19.0	20
PacifiCorp	37	22	20	4	20	17	12	36	2	28	19.8	23
Portland General Electric Company	8	31	6	14	24	17	29	7	32	6	17.4	14
Public Service Company of New Hampshire	12	11	1	8	33	17	21	34	13	7	15.7	10
Public Service Company of New Mexico	18	36	3	3	3	11	4	14	35	20	14.7	5
Public Service Company of Oklahoma	20	18	31	20	19	17	17	18	20	29	20.9	28
Southern California Edison Co.	30	13	2	16	37	6	18	11	15	4	15.2	8
Southwestern Electric Power Company	28	28	34	1	5	17	35	22	12	25	20.7	27
Southwestern Public Service Company	39	35	39	39	4	17	16	8	4	19	22.0	32
Tucson Electric Power Company	9	32	7	25	25	17	7	16	36	2	17.6	15
Virginia Electric and Power Company	13	16	29	6	11	7	31	24	27	13	17.7	16
Westar Energy (KPL)	26	37	14	27	15	17	39	31			25.8	37

Regional Panel	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Volume (%)	Percent Generation Nuclear (%)	Energy Losses (%)	Age of Plant (Depreciation/Gross Plant)	Customer Density	Regulatory Lag	Average Rank	Overall Rank
Arizona Public Service Company	*1*	*2*	*5*	*4*	*7*	*3*	*6*	*6*	*3*	*1*	*3.8*	*1*
El Paso Electric Company	6	8	3	1	1	1	7	1	4	6	3.8	1
Nevada Power Company	3	1	6	6	6	5	8	8	6	8	5.7	8
PacifiCorp	7	4	7	3	4	5	3	7	1	7	4.8	6
Public Service Company of New Mexico	4	7	2	2	2	4	1	4	7	5	3.8	1
Southern California Edison Co.	5	3	1	5	8	2	5	3	5	3	4.0	4
Southwestern Public Service Company	8	6	8	8	3	5	4	2	2	4	5.0	7
Tucson Electric Power Company	2	5	4	7	5	5	2	5	8	2	4.5	5
Salt River Project												

Productive Efficiency Rankings - 2000

(a rank of 1 indicates the most efficient performer for each metric)

Base Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*18*	*22*	*17*	*10*	*16*	*30*	*18.6*	*14*
Alabama Power Company	28	23	29	19	26	29	25.2	35
Appalachian Power Company	12	19	32	19	18	18	19.4	16
Carolina Power & Light Company	20	25	6	29	24	28	21.6	25
Columbus Southern Power Company	10	37	26	9	21	21	20.3	20
Dayton Power and Light Company	8	2	5	8	8	3	5.4	1
Detroit Edison Company	13	4	32	26	23	18	19.0	15
Duke Energy Carolinas, LLC	15	17	18	35	33	23	23.3	28
Duke Energy Indiana, Inc.	18	31	6	32	22	15	20.3	21
El Paso Electric Company	28	11	11	37	33	13	22.1	27
Entergy Arkansas, Inc.	23	17	34	33	31	37	29.1	38
Entergy Louisiana, LLC								
Entergy Mississippi, Inc.	28	15	26	16	2	32	19.8	19
Florida Power & Light Company	22	13	21	3	4	27	14.7	7
Florida Power Corporation	30	19	11	18	18	22	19.6	18
Georgia Power Company	26	25	27	25	26	28	26.0	37
Gulf Power Company	26	13	21	19	23	16	19.5	17
Idaho Power Co.	1	17	35	14	4	8	13.0	4
Indiana Michigan Power Company	38	1	23	25	38	27	25.2	34
Indianapolis Power & Light Company	13	10	16	38	33	14	20.4	22
Kansas City Power & Light Company	15	18	36	28	31	28	25.7	36
Kansas Gas and Electric Company	23	23	26	24	35	12	23.7	29
KCP&L Greater Missouri Operations Company	17	28	26	27	19	32	24.8	33
Kentucky Utilities Company	10	7	9	3	8	13	7.9	2
Monongahela Power Company	9	13	32	17	14	17	16.8	11
Nevada Power Company	27	11	1	11	7	29	14.3	6
Ohio Power Company	32	34	16	16	29	18	23.8	30
Oklahoma Gas and Electric Company	30	10	14	17	9	14	15.3	9
PacifiCorp	6	33	29	2	17	9	15.9	10
Portland General Electric Company	11	35	15	17	13	17	17.8	13
Public Service Company of New Hampshire	2	35	27	23	23	18	21.2	23
Public Service Company of New Mexico	22	34	16	26	30	3	21.8	26
Public Service Company of Oklahoma	34	13	11	3	5	6	11.8	3
Southern California Edison Co.	10	25	10	20	17	20	16.8	12
Southwestern Electric Power Company	33	26	33	20	18	18	24.5	31
Southwestern Public Service Company	29	20	6	11	1	13	13.2	5
Tucson Electric Power Company	33	11	5	33	26	21	21.3	24
Virginia Electric and Power Company	10	14	19	11	14	24	15.2	8
Westar Energy (KPL)	23	21	24	26	30	25	24.6	32

Regional Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*3*	*5*	*7*	*3*	*4*	*7*	*4.7*	*5*
El Paso Electric Company	6	2	4	8	8	4	5.4	7
Nevada Power Company	6	2	1	4	2	8	3.8	2
PacifiCorp	2	8	8	1	4	3	4.2	4
Public Service Company of New Mexico	5	8	6	6	7	1	5.6	8
Southern California Edison Co.	2	6	4	5	4	5	4.1	3
Southwestern Public Service Company	6	4	4	4	1	3	3.7	1
Tucson Electric Power Company	7	3	3	7	6	6	5.0	6
Salt River Project		7	9			8	7.8	9

Productive Efficiency Rankings - 2001

(a rank of 1 indicates the most efficient performer for each metric)

Base Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*21*	*18*	*15*	*10*	*17*	*25*	*17.5*	*13*
Alabama Power Company	24	15	24	16	22	32	22.0	24
Appalachian Power Company	12	16	31	10	12	17	15.9	8
Carolina Power & Light Company	20	28	5	23	23	30	21.3	20
Columbus Southern Power Company	13	37	16	5	13	22	17.3	11
Dayton Power and Light Company	14	2	4	3	4	11	6.2	1
Detroit Edison Company	12	24	28	37	32	18	24.9	35
Duke Energy Carolinas, LLC	13	17	13	35	33	19	21.5	22
Duke Energy Indiana, Inc.	19	17	8	27	17	21	18.1	14
El Paso Electric Company	32	11	13	37	34	9	22.4	26
Entergy Arkansas, Inc.	29	15	31	11	35	18	23.0	30
Entergy Louisiana, LLC								
Entergy Mississippi, Inc.	37	8	22	17	24	20	21.3	21
Florida Power & Light Company	31	10	19	2	11	26	16.4	9
Florida Power Corporation	27	19	9	5	6	8	12.1	3
Georgia Power Company	22	25	29	28	25	23	25.1	37
Gulf Power Company	24	16	24	21	20	14	19.6	19
Idaho Power Co.	2	20	36	23	2	30	18.7	17
Indiana Michigan Power Company	26	1	34	27	38	11	22.6	28
Indianapolis Power & Light Company	10	7	14	37	31	6	17.5	12
Kansas City Power & Light Company	10	15	37	19	27	31	22.9	29
Kansas Gas and Electric Company	20	29	25	32	33	11	24.8	34
KCP&L Greater Missouri Operations Company	14	27	30	20	18	27	22.5	27
Kentucky Utilities Company	9	6	4	12	5	22	9.5	2
Monongahela Power Company	9	15	31	17	14	5	15.0	6
Nevada Power Company	1	18	2	24	1	33	13.0	4
Ohio Power Company	28	29	22	12	28	25	23.7	32
Oklahoma Gas and Electric Company	27	7	16	23	7	11	14.8	5
PacifiCorp	6	34	25	17	17	13	18.5	15
Portland General Electric Company	20	36	10	27	15	27	22.2	25
Public Service Company of New Hampshire	14	33	29	22	22	21	23.3	31
Public Service Company of New Mexico	25	35	20	22	29	27	26.2	38
Public Service Company of Oklahoma	35	22	14	3	12	27	18.6	16
Southern California Edison Co.	14	30	12	22	16	9	17.1	10
Southwestern Electric Power Company	33	25	33	16	14	12	21.9	23
Southwestern Public Service Company	37	28	5	17	33	23	23.7	32
Tucson Electric Power Company	31	9	6	26	19	23	18.8	18
Virginia Electric and Power Company	18	11	23	12	15	14	15.2	7
Westar Energy (KPL)	16	23	31	31	26	24	25.0	36

Regional Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*4*	*4*	*6*	*2*	*4*	*6*	*3.9*	*2*
El Paso Electric Company	7	2	5	8	8	2	5.1	6
Nevada Power Company	1	3	2	5	1	9	3.3	1
PacifiCorp	3	7	8	4	4	4	4.7	5
Public Service Company of New Mexico	5	8	7	5	7	7	6.3	9
Southern California Edison Co.	3	7	4	5	4	3	4.0	3
Southwestern Public Service Company	8	6	3	4	7	6	5.7	7
Tucson Electric Power Company	7	2	3	6	4	6	4.3	4
Salt River Project		6	9			4	6.1	8

Productive Efficiency Rankings - 2002

(a rank of 1 indicates the most efficient performer for each metric)

Base Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*13*	*16*	*22*	*11*	*19*	*26*	*17.7*	*11*
Alabama Power Company	24	12	25	19	20	16	19.4	16
Appalachian Power Company	11	3	31	13	11	16	14.0	8
Carolina Power & Light Company	26	26	15	23	24	28	23.4	27
Columbus Southern Power Company	8	33	19	8	11	11	14.8	9
Dayton Power and Light Company	10	2	3	2	3	9	4.7	1
Detroit Edison Company	15	31	33	35	28	25	27.5	38
Duke Energy Carolinas, LLC	15	12	34	32	30	26	24.7	31
Duke Energy Indiana, Inc.	18	24	6	34	22	27	21.7	23
El Paso Electric Company	26	33	12	37	34	6	24.4	29
Entergy Arkansas, Inc.	20	12	24	38	37	22	25.3	35
Entergy Louisiana, LLC								
Entergy Mississippi, Inc.	34	11	24	19	24	30	23.6	28
Florida Power & Light Company	28	13	17	4	7	29	16.0	10
Florida Power Corporation	29	18	11	17	10	28	18.5	13
Georgia Power Company	26	26	29	23	25	19	24.4	30
Gulf Power Company	33	12	30	18	21	37	25.1	34
Idaho Power Co.	28	16	36	19	36	18	25.4	36
Indiana Michigan Power Company	27	1	21	29	36	6	19.7	18
Indianapolis Power & Light Company	6	11	23	4	8	31	13.5	6
Kansas City Power & Light Company	9	18	38	27	29	16	22.4	25
Kansas Gas and Electric Company	21	36	16	32	35	11	25.0	33
KCP&L Greater Missouri Operations Company	12	25	32	16	15	31	21.7	24
Kentucky Utilities Company	15	16	6	12	9	16	12.0	4
Monongahela Power Company	6	24	31	28	17	13	19.6	17
Nevada Power Company	36	8	2	15	33	28	20.1	20
Ohio Power Company	22	24	17	17	24	17	20.0	19
Oklahoma Gas and Electric Company	24	7	11	16	5	20	13.4	5
PacifiCorp	7	28	14	26	24	16	18.8	14
Portland General Electric Company	16	36	14	20	16	15	19.2	15
Public Service Company of New Hampshire	20	31	29	21	22	27	24.7	32
Public Service Company of New Mexico	22	31	17	29	28	35	26.8	37
Public Service Company of Oklahoma	14	17	16	3	1	5	9.2	3
Southern California Edison Co.	15	24	22	24	17	23	20.6	22
Southwestern Electric Power Company	31	22	30	14	14	12	20.2	21
Southwestern Public Service Company	29	29	9	5	6	6	13.7	7
Tucson Electric Power Company	30	9	6	25	21	20	18.5	12
Virginia Electric and Power Company	15	6	2	6	5	12	7.3	2
Westar Energy (KPL)	10	35	25	32	23	12	22.6	26

Regional Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*2*	*3*	*8*	*2*	*3*	*5*	*3.7*	*2*
El Paso Electric Company	*6*	*8*	*4*	*8*	*8*	*2*	*5.9*	*7*
Nevada Power Company	8	2	1	3	7	7	4.4	4
PacifiCorp	2	6	6	6	5	4	4.5	5
Public Service Company of New Mexico	4	7	5	7	6	8	6.0	8
Southern California Edison Co.	3	5	7	5	3	5	4.5	5
Southwestern Public Service Company	6	7	4	2	2	2	3.5	1
Tucson Electric Power Company	6	2	3	5	4	5	3.9	3
Salt River Project		5	9			8	7.4	9

Productive Efficiency Rankings - 2003

(a rank of 1 indicates the most efficient performer for each metric)

Base Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*25*	*17*	*15*	*15*	*18*	*31*	*19.9*	*20*
Alabama Power Company	24	19	27	22	22	29	23.7	34
Appalachian Power Company	12	8	33	5	8	9	12.5	3
Carolina Power & Light Company	24	26	5	25	27	22	21.2	25
Columbus Southern Power Company	8	34	24	6	9	11	15.2	8
Dayton Power and Light Company		2	3			6	3.5	1
Detroit Edison Company	13	30	35	36	32	19	27.3	38
Duke Energy Carolinas, LLC	15	13	33	23	28	26	22.8	30
Duke Energy Indiana, Inc.	23	13	7	32	28	26	21.5	26
El Paso Electric Company	26	11	7	37	34	26	23.4	33
Entergy Arkansas, Inc.	5	12	22	29	22	24	18.8	16
Entergy Louisiana, LLC								
Entergy Mississippi, Inc.	19	12	26	18	2	29	17.3	14
Florida Power & Light Company	30	11	10	2	2	32	14.3	6
Florida Power Corporation	30	13	13	21	11	31	19.7	18
Georgia Power Company	22	24	23	19	19	25	22.0	27
Gulf Power Company	30	17	26	24	23	18	22.7	29
Idaho Power Co.	11	23	35	16	32	22	23.0	31
Indiana Michigan Power Company	24	1	19	23	34	19	19.9	20
Indianapolis Power & Light Company	10	13	24	9	14	5	12.3	2
Kansas City Power & Light Company	9	23	33	32	31	16	24.0	35
Kansas Gas and Electric Company	19	37	22	24	36	5	23.4	32
KCP&L Greater Missouri Operations Company	13	23	23	16	9	17	16.9	12
Kentucky Utilities Company	15	20	11	8	5	19	12.8	5
Monongahela Power Company	7	30	31	32	21	13	22.2	28
Nevada Power Company	30	12	1	20	26	29	19.5	17
Ohio Power Company	21	23	20	4	25	26	19.7	19
Oklahoma Gas and Electric Company	29	5	9	16	4	12	12.5	3
PacifiCorp	7	29	25	22	24	20	21.0	24
Portland General Electric Company	12	36	13	20	15	16	18.4	15
Public Service Company of New Hampshire	23	29	28	24	24	32	26.4	37
Public Service Company of New Mexico	19	33	11	34	30	25	25.1	36
Public Service Company of Oklahoma	35	12	14	3	11	19	15.5	9
Southern California Edison Co.	11	26	22	29	21	18	20.8	23
Southwestern Electric Power Company	31	20	32	7	13	19	20.1	22
Southwestern Public Service Company	31	30	5	15	8	6	15.5	10
Tucson Electric Power Company	26	10	7	25	22	13	17.0	13
Virginia Electric and Power Company	13	5	37	5	6	24	14.9	7
Westar Energy (KPL)	11	36	19	14	16	6	16.6	11

Regional Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*5*	*4*	*6*	*2*	*3*	*8*	*4.4*	*3*
El Paso Electric Company	6	2	3	8	8	6	5.6	7
Nevada Power Company	7	3	1	3	5	8	4.4	3
PacifiCorp	2	6	8	5	5	4	4.8	6
Public Service Company of New Mexico	4	8	5	7	7	6	5.9	8
Southern California Edison Co.	2	6	8	6	4	4	4.6	5
Southwestern Public Service Company	6	7	4	3	2	1	3.5	1
Tucson Electric Power Company	6	2	4	4	4	3	3.7	2
Salt River Project		6	9			6	6.9	9

Productive Efficiency Rankings - 2004

(a rank of 1 indicates the most efficient performer for each metric)

Base Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*21*	*16*	*19*	*17*	*16*	*23*	*18.4*	*15*
Alabama Power Company	25	14	26	23	22	24	22.3	27
Appalachian Power Company	15	7	33	7	10	20	14.9	5
Carolina Power & Light Company	24	20	16	26	24	13	20.3	22
Columbus Southern Power Company	11	32	32	6	13	14	17.6	14
Dayton Power and Light Company	18	17	3	25	17	17	16.1	8
Detroit Edison Company	13	30	31	37	34	15	26.4	38
Duke Energy Carolinas, LLC	15	9	14	16	19	31	17.2	13
Duke Energy Indiana, Inc.	21	16	7	34	26	17	20.0	21
El Paso Electric Company	28	10	8	38	33	8	20.6	23
Entergy Arkansas, Inc.	8	13	17	21	25	17	16.6	11
Entergy Louisiana, LLC								
Entergy Mississippi, Inc.	33	10	16	20	32	33	23.8	32
Florida Power & Light Company	32	11	12	1	3	25	13.8	4
Florida Power Corporation	30	10	8	17	7	24	16.0	7
Georgia Power Company	25	25	30	25	23	15	23.6	31
Gulf Power Company	33	12	21	32	24	31	25.4	35
Idaho Power Co.	4	22	27	28	28	22	21.8	26
Indiana Michigan Power Company	21	1	26	27	35	20	21.3	24
Indianapolis Power & Light Company	9	11	12	12	9	20	12.0	3
Kansas City Power & Light Company	8	25	32	34	33	12	23.9	33
Kansas Gas and Electric Company	15	37	26	27	36	9	24.9	34
KCP&L Greater Missouri Operations Company	13	21	27	23	13	18	19.0	19
Kentucky Utilities Company	16	13	9	6	3	22	11.2	1
Monongahela Power Company	9	24	29	16	14	7	16.3	10
Nevada Power Company	26	11	1	12	22	26	16.2	9
Ohio Power Company	22	21	29	13	29	24	22.7	29
Oklahoma Gas and Electric Company	32	9	10	13	3	25	15.2	6
PacifiCorp	6	27	37	22	26	22	23.1	30
Portland General Electric Company	13	36	19	18	11	22	19.6	20
Public Service Company of New Hampshire	22	33	26	27	25	24	26.1	37
Public Service Company of New Mexico	15	33	11	34	30	13	22.6	28
Public Service Company of Oklahoma	33	25	30	3	7	15	18.6	16
Southern California Edison Co.	14	30	32	29	23	27	25.6	36
Southwestern Electric Power Company	28	29	26	7	12	11	18.6	16
Southwestern Public Service Company	34	27	7	8	4	21	16.6	12
Tucson Electric Power Company	26	8	9	30	24	18	18.8	18
Virginia Electric and Power Company	23	8	4	4	10	22	11.6	2
Westar Energy (KPL)	13	35	27	15	25	16	21.5	25

Regional Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*5*	*4*	*6*	*4*	*3*	*5*	*4.2*	*4*
El Paso Electric Company	7	2	3	8	8	2	5.0	6
Nevada Power Company	7	3	1	2	4	6	3.7	1
PacifiCorp	2	5	8	4	6	5	4.8	5
Public Service Company of New Mexico	3	7	4	7	7	3	5.0	7
Southern California Edison Co.	2	7	8	5	4	7	5.3	8
Southwestern Public Service Company	7	6	4	2	1	5	3.9	2
Tucson Electric Power Company	6	2	4	6	5	4	4.2	3
Salt River Project								

Productive Efficiency Rankings - 2005

(a rank of 1 indicates the most efficient performer for each metric)

Base Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*21*	*19*	*17*	*21*	*25*	*29*	*21.9*	*24*
Alabama Power Company	26	16	29	24	28	26	24.5	31
Appalachian Power Company	16	13	27	4	14	25	16.3	13
Carolina Power & Light Company	24	17	16	26	20	16	19.8	20
Columbus Southern Power Company	16	29	24	5	19	26	19.7	19
Dayton Power and Light Company	19	32	4	7	19	7	14.6	7
Detroit Edison Company	15	35	34	36	35	3	26.0	36
Duke Energy Carolinas, LLC	15	6	21	23	25	22	18.6	18
Duke Energy Indiana, Inc.	16	11	6	32	18	25	18.0	15
El Paso Electric Company	32	17	10	38	33	11	23.4	27
Entergy Arkansas, Inc.	2	9	12	23	6	16	11.2	2
Entergy Louisiana, LLC								
Entergy Mississippi, Inc.	18	7	10	18	1	26	13.1	4
Florida Power & Light Company	31	12	7	7	3	33	15.2	8
Florida Power Corporation	34	12	25	32	24	27	25.4	34
Georgia Power Company	28	26	27	25	26	22	25.7	35
Gulf Power Company	32	11	25	34	29	28	26.0	37
Idaho Power Co.	3	19	22	22	18	27	18.4	16
Indiana Michigan Power Company	18	1	35	19	35	12	19.9	21
Indianapolis Power & Light Company	8	6	15	16	16	10	11.6	3
Kansas City Power & Light Company	10	19	32	32	33	27	25.4	33
Kansas Gas and Electric Company	19	36	26	28	36	7	25.3	32
KCP&L Greater Missouri Operations Company	16	25	27	25	16	37	24.1	30
Kentucky Utilities Company	24	16	11	9	13	7	13.1	5
Monongahela Power Company	10	23	30	12	11	8	15.4	10
Nevada Power Company	19	11	1	19	5	25	13.2	6
Ohio Power Company	23	20	27	5	30	23	21.2	22
Oklahoma Gas and Electric Company	32	14	8	10	7	28	16.4	14
PacifiCorp	7	27	37	20	29	24	23.7	29
Portland General Electric Company	6	35	21	23	15	12	18.6	17
Public Service Company of New Hampshire	24	31	27	29	26	32	28.0	38
Public Service Company of New Mexico	17	32	8	34	33	15	23.2	26
Public Service Company of Oklahoma	35	21	22	2	3	13	15.6	11
Southern California Edison Co.	7	32	24	31	23	25	23.6	28
Southwestern Electric Power Company	32	27	34	5	19	11	21.2	23
Southwestern Public Service Company	35	28	5	11	5	12	15.9	12
Tucson Electric Power Company	21	7	8	21	18	18	15.3	9
Virginia Electric and Power Company	25	3	6	6	11	14	10.6	1
Westar Energy (KPL)	12	35	30	15	24	17	21.9	25

Regional Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*5*	*3*	*7*	*4*	*5*	*6*	*4.9*	*4*
El Paso Electric Company	8	3	4	8	8	2	5.3	8
Nevada Power Company	5	2	1	3	2	6	2.9	1
PacifiCorp	2	6	8	4	6	6	5.2	5
Public Service Company of New Mexico	4	7	3	7	7	4	5.3	6
Southern California Edison Co.	2	7	7	6	5	6	5.3	7
Southwestern Public Service Company	7	6	4	2	2	3	3.8	3
Tucson Electric Power Company	5	2	4	3	3	4	3.4	2
Salt River Project								

Productive Efficiency Rankings - 2006

(a rank of 1 indicates the most efficient performer for each metric)

Base Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*26*	*20*	*17*	*23*	*22*	*20*	*21.2*	*21*
Alabama Power Company	26	18	31	24	25	21	24.1	33
Appalachian Power Company	16	4	28	2	7	30	14.3	6
Carolina Power & Light Company	25	17	14	19	23	12	18.2	14
Columbus Southern Power Company	12	32	15	5	10	23	15.9	10
Dayton Power and Light Company	15	34	6	10	13	13	14.9	8
Detroit Edison Company	11	36	34	36	35	20	28.5	39
Duke Energy Carolinas, LLC	16	4	15	31	23	19	17.6	11
Duke Energy Indiana, Inc.	25	15	6	36	36	19	22.8	26
El Paso Electric Company	26	25	16	39	35	3	23.7	30
Entergy Arkansas, Inc.	19	18	11	30	37	14	21.3	23
Entergy Louisiana, LLC	35	12	4	23	11	26	18.4	15
Entergy Mississippi, Inc.	37	11	12	26	36	30	24.9	34
Florida Power & Light Company	36	12	15	6	22	23	18.8	17
Florida Power Corporation	30	14	26	14	7	26	19.2	18
Georgia Power Company	28	27	30	21	21	34	26.8	37
Gulf Power Company	34	11	23	36	24	16	23.7	30
Idaho Power Co.	2	20	25	23	9	17	15.9	9
Indiana Michigan Power Company	17	1	29	21	33	27	21.1	20
Indianapolis Power & Light Company	13	14	17	21	16	9	14.9	7
Kansas City Power & Light Company	7	24	24	32	28	30	23.8	32
Kansas Gas and Electric Company	10	36	36	28	35	7	25.2	35
KCP&L Greater Missouri Operations Company	16	30	28	30	19	15	22.9	27
Kentucky Utilities Company	24	7	13	5	4	4	9.3	1
Monongahela Power Company	9	19	30	13	7	7	14.1	5
Nevada Power Company	22	8	1	13	1	37	13.6	4
Ohio Power Company	23	24	21	7	31	23	21.2	22
Oklahoma Gas and Electric Company	27	8	4	13	2	27	13.3	3
PacifiCorp	6	29	38	19	24	24	23.2	28
Portland General Electric Company	5	36	28	20	12	9	18.1	13
Public Service Company of New Hampshire	20	31	29	30	24	33	27.6	38
Public Service Company of New Mexico	14	31	11	30	29	23	22.7	25
Public Service Company of Oklahoma	36	14	35	3	20	26	22.3	24
Southern California Edison Co.	8	31	29	32	21	22	23.6	29
Southwestern Electric Power Company	27	18	32	11	14	21	20.3	19
Southwestern Public Service Company	35	28	6	11	22	12	18.7	16
Tucson Electric Power Company	24	14	5	23	19	22	17.6	12
Virginia Electric and Power Company	17	7	11	6	9	13	10.4	2
Westar Energy (KPL)	10	37	34	18	26	30	25.8	36

Regional Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*6*	*3*	*6*	*4*	*5*	*5*	*4.6*	*4*
El Paso Electric Company	6	5	5	8	8	1	5.4	8
Nevada Power Company	6	1	1	2	1	8	3.1	1
PacifiCorp	2	6	8	4	5	5	4.9	5
Public Service Company of New Mexico	3	7	4	6	6	5	5.1	6
Southern California Edison Co.	2	7	7	7	4	5	5.2	7
Southwestern Public Service Company	7	5	4	2	5	3	4.2	3
Tucson Electric Power Company	6	2	3	4	4	5	3.6	2
Salt River Project								

Productive Efficiency Rankings - 2007

(a rank of 1 indicates the most efficient performer for each metric)

Base Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*25*	*22*	*26*	*18*	*23*	*21*	*22.2*	*26*
Alabama Power Company	27	17	34	28	29	18	25.0	35
Appalachian Power Company	18	3	26	4	10	29	14.7	6
Carolina Power & Light Company	26	20	17	17	31	16	21.0	21
Columbus Southern Power Company	13	29	20	2	8	29	16.6	10
Dayton Power and Light Company	14	37	6	12	25	24	19.5	18
Detroit Edison Company	10	36	36	37	35	18	28.5	38
Duke Energy Carolinas, LLC	15	4	13	23	22	22	16.2	9
Duke Energy Indiana, Inc.	15	13	4	36	22	29	19.7	19
El Paso Electric Company	27	24	11	39	34	12	24.2	30
Entergy Arkansas, Inc.	4	16	14	27	11	11	13.8	4
Entergy Louisiana, LLC	37	14	7	24	26	5	18.5	15
Entergy Mississippi, Inc.	32	13	13	20	4	19	16.6	10
Florida Power & Light Company	36	10	12	5	3	24	14.7	5
Florida Power Corporation	31	12	29	28	16	29	24.0	29
Georgia Power Company	31	24	27	20	20	14	22.5	27
Gulf Power Company	34	9	28	35	27	19	25.1	36
Idaho Power Co.	2	20	27	29	2	26	17.4	13
Indiana Michigan Power Company	18	1	29	21	36	22	21.0	22
Indianapolis Power & Light Company	8	14	9	18	12	19	13.2	3
Kansas City Power & Light Company	8	25	20	32	30	12	21.0	23
Kansas Gas and Electric Company	9	37	35	29	34	11	25.4	37
KCP&L Greater Missouri Operations Company	13	27	24	28	15	5	18.6	16
Kentucky Utilities Company	21	9	10	3	4	14	10.1	1
Monongahela Power Company	22	21	23	22	16	11	18.9	17
Nevada Power Company	32	5	1	16	27	27	17.8	14
Ohio Power Company	24	8	22	8	30	30	20.1	20
Oklahoma Gas and Electric Company	30	10	6	8	8	29	14.9	7
PacifiCorp	12	29	36	9	20	26	22.0	24
Portland General Electric Company	14	35	26	23	17	33	24.6	33
Public Service Company of New Hampshire	20	35	31	33	28	26	28.5	39
Public Service Company of New Mexico	16	30	12	27	30	18	22.2	25
Public Service Company of Oklahoma	32	21	39	4	24	28	24.4	31
Southern California Edison Co.	8	30	27	35	24	25	24.8	34
Southwestern Electric Power Company	28	24	29	8	16	33	22.9	28
Southwestern Public Service Company	33	26	7	10	12	6	15.6	8
Tucson Electric Power Company	24	19	4	21	22	13	17.1	12
Virginia Electric and Power Company	13	13	14	9	4	20	11.9	2
Westar Energy (KPL)	12	36	34	21	34	12	24.5	32

Regional Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*5*	*3*	*7*	*4*	*4*	*5*	*4.4*	*4*
El Paso Electric Company	6	4	4	8	8	3	5.4	8
Nevada Power Company	8	1	1	3	6	7	4.0	3
PacifiCorp	2	6	8	2	4	6	4.5	5
Public Service Company of New Mexico	3	7	5	6	7	4	5.2	6
Southern California Edison Co.	2	7	7	7	4	6	5.2	7
Southwestern Public Service Company	7	5	4	3	2	2	3.7	2
Tucson Electric Power Company	5	2	3	5	3	4	3.5	1
Salt River Project								

Productive Efficiency Rankings - 2008

(a rank of 1 indicates the most efficient performer for each metric)

Base Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*26*	*16*	*27*	*21*	*27*	*22*	*22.8*	*30*
Alabama Power Company	29	18	32	27	29	21	25.9	35
Appalachian Power Company	14	2	30	3	9	14	11.8	2
Carolina Power & Light Company	24	17	11	18	21	14	17.3	11
Columbus Southern Power Company	12	35	18	5	14	28	18.4	15
Dayton Power and Light Company	16	38	6	5	25	15	17.4	12
Detroit Edison Company	9	37	34	34	34	21	28.1	37
Duke Energy Carolinas, LLC	16	8	10	20	22	21	16.0	10
Duke Energy Indiana, Inc.	19	13	26	33	28	18	22.6	28
El Paso Electric Company	28	22	12	35	34	23	25.4	34
Entergy Arkansas, Inc.	6	19	39	22	31	23	23.0	31
Entergy Louisiana, LLC	38	17	6	22	20	8	18.2	14
Entergy Mississippi, Inc.	31	12	12	25	2	12	15.4	9
Florida Power & Light Company	35	9	12	1	2	18	12.6	3
Florida Power Corporation	33	10	27	21	13	18	20.2	19
Georgia Power Company	30	21	25	21	22	26	23.8	33
Gulf Power Company	33	6	23	34	24	16	22.5	26
Idaho Power Co.	2	16	23	34	13	26	18.9	17
Indiana Michigan Power Company	18	1	33	19	35	14	19.8	18
Indianapolis Power & Light Company	8	14	18	22	16	2	13.1	4
Kansas City Power & Light Company	7	23	18	35	32	12	21.2	21
Kansas Gas and Electric Company	11	35	31	29	35	18	26.5	36
KCP&L Greater Missouri Operations Company	11	31	26	32	19	25	23.8	32
Kentucky Utilities Company	21	8	11	6	5	29	13.3	5
Monongahela Power Company	16	16	28	17	5	8	14.7	6
Nevada Power Company	26	9	2	17	5	31	14.7	7
Ohio Power Company	24	27	20	11	32	23	22.6	27
Oklahoma Gas and Electric Company	29	9	12	6	10	27	15.3	8
PacifiCorp	10	29	35	9	18	26	21.3	23
Portland General Electric Company	15	35	28	23	17	12	21.4	24
Public Service Company of New Hampshire	20	33	33	33	28	32	29.6	39
Public Service Company of New Mexico	20	29	9	27	28	25	22.8	29
Public Service Company of Oklahoma	34	25	1	4	9	34	17.7	13
Southern California Edison Co.	9	29	20	38	25	8	21.3	22
Southwestern Electric Power Company	28	22	32	10	17	22	21.7	25
Southwestern Public Service Company	35	24	7	13	21	13	18.6	16
Tucson Electric Power Company	23	20	4	22	29	24	20.2	20
Virginia Electric and Power Company	11	7	15	11	4	24	11.7	1
Westar Energy (KPL)	14	35	34	23	31	33	28.2	38

Regional Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*6*	*2*	*7*	*4*	*5*	*5*	*4.6*	*5*
El Paso Electric Company	7	4	5	7	8	5	5.8	8
Nevada Power Company	6	2	1	3	1	6	3.1	1
PacifiCorp	2	7	8	2	4	6	4.5	3
Public Service Company of New Mexico	3	7	4	6	5	5	4.8	7
Southern California Edison Co.	2	6	6	8	4	2	4.6	6
Southwestern Public Service Company	7	5	4	4	5	3	4.5	3
Tucson Electric Power Company	4	3	3	4	5	6	4.1	2
Salt River Project								

Productive Efficiency Rankings - 2009

(a rank of 1 indicates the most efficient performer for each metric)

Base Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*28*	*16*	*20*	*22*	*27*	*16*	*21.3*	*25*
Alabama Power Company	28	17	34	24	26	21	25.0	34
Appalachian Power Company	13	2	39	4	9	26	15.2	8
Carolina Power & Light Company	32	16	14	15	32	13	20.3	22
Columbus Southern Power Company	13	32	25	5	10	31	19.3	16
Dayton Power and Light Company	20	37	6	12	25	9	18.1	13
Detroit Edison Company	9	36	33	34	33	28	28.5	37
Duke Energy Carolinas, LLC	15	5	10	16	15	16	12.7	1
Duke Energy Indiana, Inc.	22	10	27	32	27	9	20.7	23
El Paso Electric Company	19	22	8	36	32	19	22.5	30
Entergy Arkansas, Inc.	8	15	23	26	27	20	19.6	18
Entergy Louisiana, LLC	22	17	5	12	3	25	13.8	4
Entergy Mississippi, Inc.	27	13	6	20	19	12	16.0	10
Florida Power & Light Company	34	8	6	4	3	23	12.8	2
Florida Power Corporation	36	9	19	14	9	30	19.3	15
Georgia Power Company	34	19	16	18	12	12	18.2	14
Gulf Power Company	35	7	21	31	20	27	23.2	33
Idaho Power Co.	4	15	21	37	29	12	19.4	17
Indiana Michigan Power Company	25	1	30	21	34	15	20.8	24
Indianapolis Power & Light Company	11	14	10	26	15	2	12.9	3
Kansas City Power & Light Company	9	24	20	34	28	19	22.3	28
Kansas Gas and Electric Company	9	37	32	33	36	15	26.7	36
KCP&L Greater Missouri Operations Company	17	27	27	27	14	26	23.0	32
Kentucky Utilities Company	22	7	16	12	6	27	14.8	6
Monongahela Power Company	22	21	34	17	6	28	21.3	26
Nevada Power Company	31	9	1	20	22	24	17.6	12
Ohio Power Company	23	22	26	9	29	30	22.9	31
Oklahoma Gas and Electric Company	22	11	22	2	7	25	14.6	5
PacifiCorp	12	30	34	7	17	23	20.2	21
Portland General Electric Company	16	35	22	20	13	30	22.4	29
Public Service Company of New Hampshire	20	35	30	36	31	24	29.4	38
Public Service Company of New Mexico	15	30	10	31	26	9	20.0	19
Public Service Company of Oklahoma	10	26	36	3	2	15	15.2	7
Southern California Edison Co.	7	27	26	38	24	31	25.3	35
Southwestern Electric Power Company	24	21	23	10	12	14	17.1	11
Southwestern Public Service Company	23	28	6	12	13	14	15.8	9
Tucson Electric Power Company	25	15	3	31	30	18	20.1	20
Virginia Electric and Power Company	31	29	10	13	35	16	22.0	27
Westar Energy (KPL)	17	35	36	25	33	31	29.5	39

Regional Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*7*	*2*	*7*	*4*	*5*	*4*	*4.6*	*6*
El Paso Electric Company	4	4	4	7	8	4	5.0	7
Nevada Power Company	8	2	1	3	4	5	3.6	1
PacifiCorp	3	7	8	2	3	6	4.5	5
Public Service Company of New Mexico	3	7	5	6	5	2	4.4	3
Southern California Edison Co.	2	6	7	8	4	7	5.6	8
Southwestern Public Service Company	5	6	4	3	3	4	3.9	2
Tucson Electric Power Company	6	2	3	6	7	5	4.5	4
Salt River Project								

Productive Efficiency Rankings - 2010

(a rank of 1 indicates the most efficient performer for each metric)

Base Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*27*	*13*	*19*	*27*	*28*	*21*	*22.2*	*27*
Alabama Power Company	28	20	36	24	29	27	27.4	38
Appalachian Power Company	24	6	27	2	14	21	15.4	6
Carolina Power & Light Company	31	16	12	16	30	20	20.8	19
Columbus Southern Power Company	18	32	30	9	14	14	19.3	15
Dayton Power and Light Company	20	38	6	23	29	8	20.4	18
Detroit Edison Company	8	37	35	30	33	15	26.3	35
Duke Energy Carolinas, LLC	19	3	11	27	24	21	17.3	11
Duke Energy Indiana, Inc.	20	16	7	32	18	8	16.7	9
El Paso Electric Company	17	17	10	36	29	17	20.8	20
Entergy Arkansas, Inc.	9	12	14	24	28	9	16.0	7
Entergy Louisiana, LLC	31	18	5	8	16	3	13.5	5
Entergy Mississippi, Inc.	18	11	8	12	2	18	11.3	3
Florida Power & Light Company	27	10	9	2	2	11	9.9	1
Florida Power Corporation	34	6	23	26	12	26	21.1	24
Georgia Power Company	35	22	24	15	17	23	22.4	30
Gulf Power Company	38	8	23	20	20	27	22.4	31
Idaho Power Co.	3	13	23	37	30	22	21.0	23
Indiana Michigan Power Company	20	1	32	23	34	16	20.9	22
Indianapolis Power & Light Company	14	13	10	17	16	10	13.1	4
Kansas City Power & Light Company	9	26	19	35	30	30	24.7	33
Kansas Gas and Electric Company	10	36	32	32	35	10	25.8	34
KCP&L Greater Missouri Operations Company	15	27	25	18	11	28	20.4	17
Kentucky Utilities Company	24	11	13	11	7	33	16.3	8
Monongahela Power Company	30	19	20	14	12	13	17.7	13
Nevada Power Company	26	7	1	14	9	4	10.2	2
Ohio Power Company	23	24	31	16	33	17	23.9	32
Oklahoma Gas and Electric Company	27	22	24	6	12	29	19.7	16
PacifiCorp	10	30	32	6	20	28	20.8	21
Portland General Electric Company	13	35	23	18	13	27	21.2	25
Public Service Company of New Hampshire	21	32	33	35	26	26	28.7	39
Public Service Company of New Mexico	15	28	10	33	28	21	22.3	28
Public Service Company of Oklahoma	14	26	38	4	3	25	18.1	14
Southern California Edison Co.	8	27	30	39	24	31	26.3	36
Southwestern Electric Power Company	25	21	33	6	14	35	22.3	28
Southwestern Public Service Company	24	28	7	17	13	18	17.7	12
Tucson Electric Power Company	28	15	3	24	33	27	21.5	26
Virginia Electric and Power Company	14	16	14	24	9	27	17.1	10
Westar Energy (KPL)	15	35	35	26	34	18	27.0	37

Regional Panel	Production O&M	Transmission O&M	Distribution O&M	Customer and A&G Expenses	Total Non-Fuel O&M	Plant Investment	Overall Average	Overall Rank
Arizona Public Service Company	*7*	*2*	*6*	*4*	*6*	*4*	*4.7*	*4*
El Paso Electric Company	4	3	4	7	6	4	4.6	3
Nevada Power Company	7	2	1	3	2	2	2.5	1
PacifiCorp	3	7	8	2	4	7	4.8	5
Public Service Company of New Mexico	3	7	4	6	6	5	4.9	7
Southern California Edison Co.	2	6	8	8	5	6	5.7	8
Southwestern Public Service Company	5	6	4	3	3	4	4.1	2
Tucson Electric Power Company	7	3	3	4	7	6	4.8	5
Salt River Project								

Benchmarking Workpapers
Comparable Groups

	Base Panel	Regional Panel	Nuclear Panel
Arizona Public Service Company	X	X	X
Alabama Power Company	X		
Appalachian Power Company	X		
Carolina Power & Light Company	X		
Columbus Southern Power Company	X		
Dayton Power and Light Company	X		
Detroit Edison Company	X		X
Duke Energy Carolinas, LLC	X		
Duke Energy Indiana, Inc.	X		
El Paso Electric Company	X	X	
Entergy Arkansas, Inc.	X		
Entergy Louisiana, LLC	X		
Entergy Mississippi, Inc.	X		
Florida Power & Light Company	X		
Florida Power Corporation	X		
Georgia Power Company	X		
Gulf Power Company	X		
Idaho Power Co.	X		
Indiana Michigan Power Company	X		X
Indianapolis Power & Light Company	X		
Kansas City Power & Light Company	X		X
Kansas Gas and Electric Company	X		X
KCP&L Greater Missouri Operations Company	X		
Kentucky Utilities Company	X		
Monongahela Power Company	X		
Nevada Power Company	X	X	
Ohio Power Company	X		
Oklahoma Gas and Electric Company	X		
PacifiCorp	X	X	
Portland General Electric Company	X		
Public Service Company of New Hampshire	X		
Public Service Company of New Mexico	X	X	
Public Service Company of Oklahoma	X		
Southern California Edison Co.	X	X	X
Southwestern Electric Power Company	X		
Southwestern Public Service Company	X	X	
Tucson Electric Power Company	X	X	
Virginia Electric and Power Company	X		
Westar Energy (KPL)	X		

Benchmarking Workpapers
Definitions

Situational Assessment

Metric	Unit	Calculation
Percent Sales (MWh) Residential	percent (%)	Residential Electric Sales Vol (MWh) / Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh)
Percent Sales (MWh) Other	percent (%)	Other Electric Sales Vol (MWh) / Total Electricity Sales Vol (MWh)
Use per Customer	MWh/customer	Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh) / Ult Consumer Electric Customers
Change in Customers (%)	percent (%)	Change in Customers (%) YoY
Change in Sales Volume (%)	percent (%)	Change in MWh Sales to Ult. Consumer vs. 5 Year Average
Percent Generation Nuclear (%)	percent (%)	Nuclear Generation (MWh) / Net Generation (MWh)
Energy Losses (%)	percent (%)	Energy Losses (MWh) / Total Disposition of Energy (MWh)
Age of Plant (Depreciation/Gross Plant)	percent (%)	Accum Deprec-Total Elec Plant ($000) / Total Util Plant-Electric ($000)
Customer Density	customer/sq. mile	Ult Consumer Electric Customers / Service Territory (sq. miles)
Regulatory Lag	months	Rate Case Lag since last case as defined by Regulatory Research Associates

Productive Efficiency

Metric Group	Metric	Unit	Calculation
Production O&M	Production O&M per Customer	$/customer	Production O&M Exp less Rents and Purchased Power ($000) / Ult Consumer Electric Customers
	Production O&M per MWh Generated	$/MWh	Production O&M Exp less Rents and Purchased Power ($000) / Net Generation (MWh)
Transmission O&M	Transmission O&M per Customer	$/customer	Transmiss-O&M Exp ($000) / Ult Consumer Electric Customers
	Transmission O&M per kWh Sold	$/kWh	Transmiss-O&M Exp ($000) / Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh)
	Transmission O&M per Mile of Transmission Line	$/mile	Transmiss-O&M Exp ($000) / Length of Transmission Lines (Miles)
Distribution O&M	Distribution O&M per Customer	$/customer	Distr-O&M Exp ($000) / Ult Consumer Electric Customers
	Distribution O&M per MWh Sold	$/MWh	Distr-O&M Exp ($000) / Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh)
Customer and A&G Expenses	Customer and A&G Expenses per Customer	$/customer	Customer Accounts Exp plus Customer Service Exp plus Sales Exp plus A&G Exp ($000) / Ult Consumer Electric Customers
	Customer and A&G Expenses per MWh Sold	$/MWh	Customer Accounts Exp plus Customer Service Exp plus Sales Exp plus A&G Exp ($000) / Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh)
Total Non-Fuel O&M	Total Non-Fuel O&M per Customer	$/customer	Total Electric O&M Exp less Fuel Exp less Purchased Power less Franchise Requirements less Rents ($000) / Ult Consumer Electric Customers
	Total Non-Fuel O&M per MWh Sold	$/MWh	Total Electric O&M Exp less Fuel Exp less Purchased Power less Franchise Requirements less Rents ($000) / Tot Sales: Ult Cnsmr-Mwhrs Sold (MWh)
Plant Investment	Production Plant Additions	percent (%)	Total Production Plant-Addns($000) / Total Production Plant-BOY($000)
	Transmission Plant Additions	percent (%)	Total Transmission Plant-Addns($000) / Total Transmission Plant-BOY($000)
	Distribution Plant Additions	percent (%)	Total Distr Plant-Addns($000) / Total Distr Plant-BOY($000)
	Total Plant Additions	percent (%)	Total Elec Plt In Service-Addns($000) / Total Elec Plt In Service-BOY($000)

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

Error

An error occurred while processing this page. See the system log for more details.

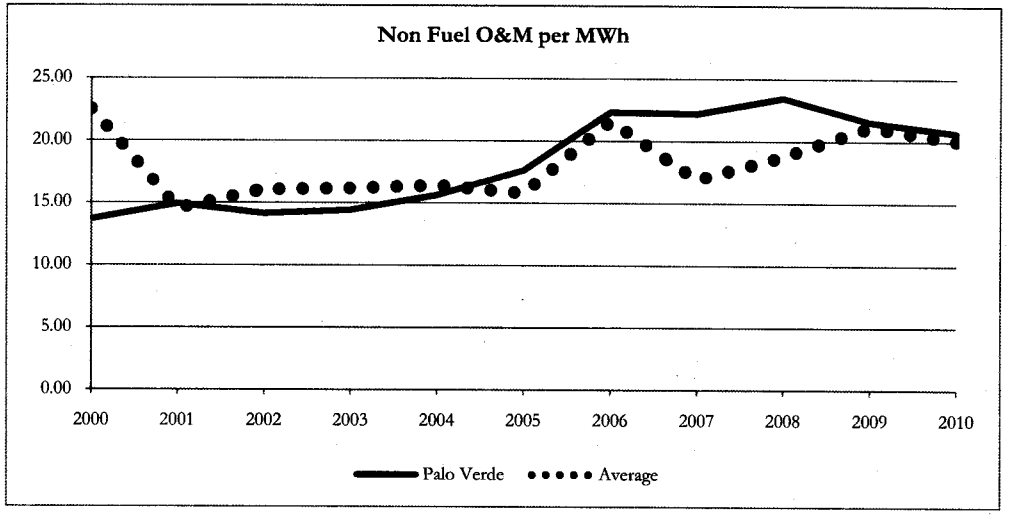
Error

An error occurred while processing this page. See the system log for more details.

	Base Panel	Expanded Base Panel	High Growth Panel	Regional Panel	Nuclear Panel	Industry Wide	Other
Safety/Customer Service/Reliability							
Injury Incident Rate						✓	
Residential Customer Satisfaction						✓	
SAIFI /SAIDI/CAIDI/MAIFI						✓	
Capacity Factor							
Base Load Coal Performance – By Unit							
Capacity Factor							✓
Equivalent Availability Factor							✓
Equivalent Forced Outage Rate							✓
Base Load Coal Performance – By Plant							
Fuel costs ($/MWh)							✓
Non-fuel O&M costs ($/MWh)							✓
Nuclear Performance – By Unit							
Capacity Factor							✓
Equivalent Availability Factor							✓
Equivalent Forced Outage Rate							✓
Nuclear Performance – By Plant							
Fuel costs ($/MWh)							✓
Non-fuel Operating costs ($/MWh)							✓
Non-fuel Maintenance costs ($/MWh)							✓
Sustainability							
CO2 (Tons per year)							✓
NOX (Tons per year)							✓
SO2 (Tons per year)							✓
Non-Fuel Operating and Maintenance Costs							
Steam Production (coal-fired) ($/MWh)	✓						
Other Production (gas-fired) ($/MWh)	✓						✓
Distribution O&M ($/Customer, $/Unit Sales)	✓		✓				
Transmission O&M ($/Line Mile, $/Unit Sales)	✓		✓				
Customer Expense (Sum of: Customer accounts, Customer service, and Sales expense) ($/ Customer, $/ Unit Sales)	✓		✓				
A&G Expense ($/MWh Sales, $/Sales Revenue)	✓						
Total Electric O&M (per MWh sales, per Customer	✓						
Capital Investment							
Total Electric Plant (% change)	✓		✓				
Steam Production Plant ($ invested)	✓						
Nuclear Production Plant ($ invested, $ MWh generated)					✓		
Other Production Plant ($/MWh generated)	✓						
Transmission Plant ($ invested and % change)	✓						
Distribution Plant per Customer ($ invested per Customer; $ invested per Customer vs. Customers per Square Mile)	✓		✓	✓			
Distribution Plant ($ invested over study period; % change)	✓		✓				
Distribution Plant per New Customer	✓		✓	✓			

	Base Panel	Expanded Base Panel	High Growth Panel	Regional Panel	Nuclear Panel	Industry Wide	Other
Management, Labor and Regulatory Expense							
Employees (per customer, per MWh sales)	✓						
Salaries and Wages (per customer, per MWh sales, and per employee)	✓						
Regulatory Commission Expenses (total $$)	✓				✓		
Financial Performance							
Earned Return on Average Equity	✓	✓	✓		✓		
Earned Return on Average Assets	✓	✓	✓		✓		
Earnings Growth Rates	✓	✓	✓		✓		
Total Return to Parent Company	✓	✓	✓		✓		
Funds Flow from Operations/Average Debt							✓
FFO Interest Coverage							✓
Total Debt/Capitalization Ratio							✓
Debt and Commercial Paper Ratings							✓
Net Cash Flow/Capex	✓	✓	✓	✓	✓		
Dividend Payout Ratio to Parent	✓						
Construction Work in Progress/Net Property, Plant and Equipment	✓	✓	✓	✓	✓		
Hedging	Qualitative Assessment						
Funds Paid Among Affiliates	Qualitative Assessment						

Nuclear Non-Fuel O&M Expense by Plant



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Palo Verde	*13.66*	*14.90*	*14.11*	*14.39*	*15.60*	*17.62*	*22.31*	*22.20*	*23.45*	*21.53*	*20.66*
Beaver Valley	30.94	22.82	23.48	28.40	22.70	21.92	84.32	55.78	53.67	55.60	NA
Callaway	9.00	14.89	15.56	11.59	20.99	18.14	11.77	15.82	16.38	10.91	18.28
Comanche Peak	10.02	9.17	13.37	12.05	13.09	14.55	10.64	12.28	13.01	12.15	NA
Davis-Besse	17.42	10.74	NM	NM	18.06	15.76	16.97	12.61	13.71	10.55	NA
Diablo Canyon	10.59	10.38	13.26	13.09	19.94	13.58	13.84	13.87	15.37	18.04	14.17
Donald C. Cook	107.80	17.58	20.46	18.58	13.46	12.43	14.43	12.53	15.30	25.92	15.64
Fort Calhoun Nuclear Station	22.91	24.67	21.64	25.57	14.47	22.73	19.81	7.53	11.47	NA	NA
Prairie Island	11.19	14.17	15.81	14.32	15.06	15.30	19.94	15.13	16.28	22.36	22.58
San Onofre	15.55	17.33	18.43	17.10	27.46	16.56	30.41	21.27	26.81	31.02	37.17
South Texas Project	8.79	10.56	10.73	12.74	8.64	11.73	10.90	11.24	12.53	12.65	NA
V.C. Summer	13.80	11.68	11.62	12.58	11.24	12.79	13.33	13.04	15.17	17.56	16.26
Wolf Creek	12.31	10.20	11.96	11.54	11.49	13.73	12.60	11.77	15.42	15.63	16.08

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Palo Verde	*13.66*	*14.90*	*14.11*	*14.39*	*15.60*	*17.62*	*22.31*	*22.20*	*23.45*	*21.53*	*20.66*
Average	22.53	14.52	16.03	16.14	16.38	15.77	21.58	16.91	18.76	21.13	20.03
Palo Verde Rank	7	9	6	8	8	10	11	12	11	8	6

Source: SNL Financial

Underground Distribution Systems

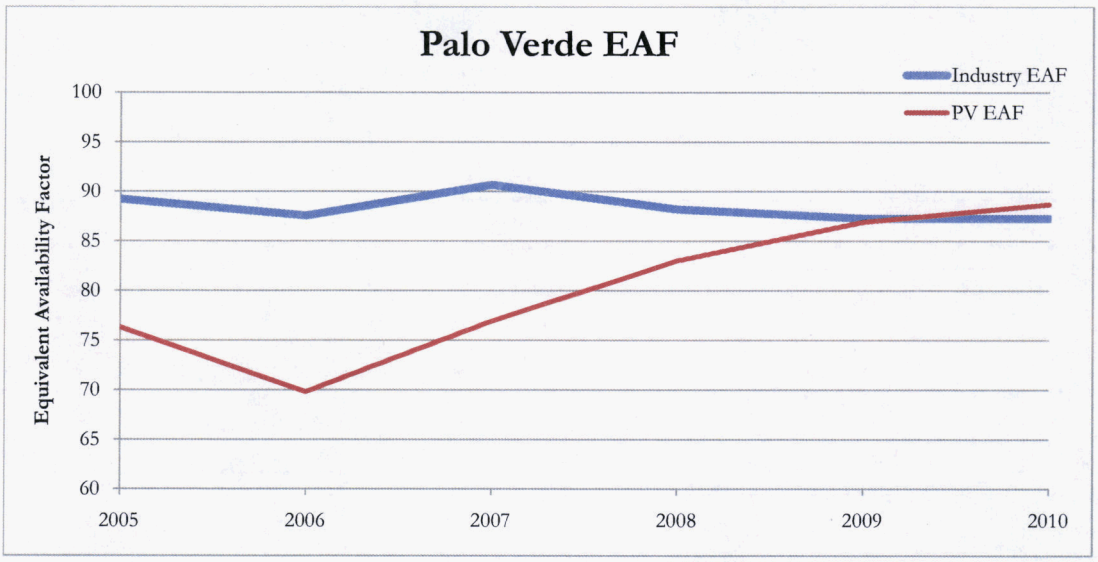
Labor Efficiency Metrics

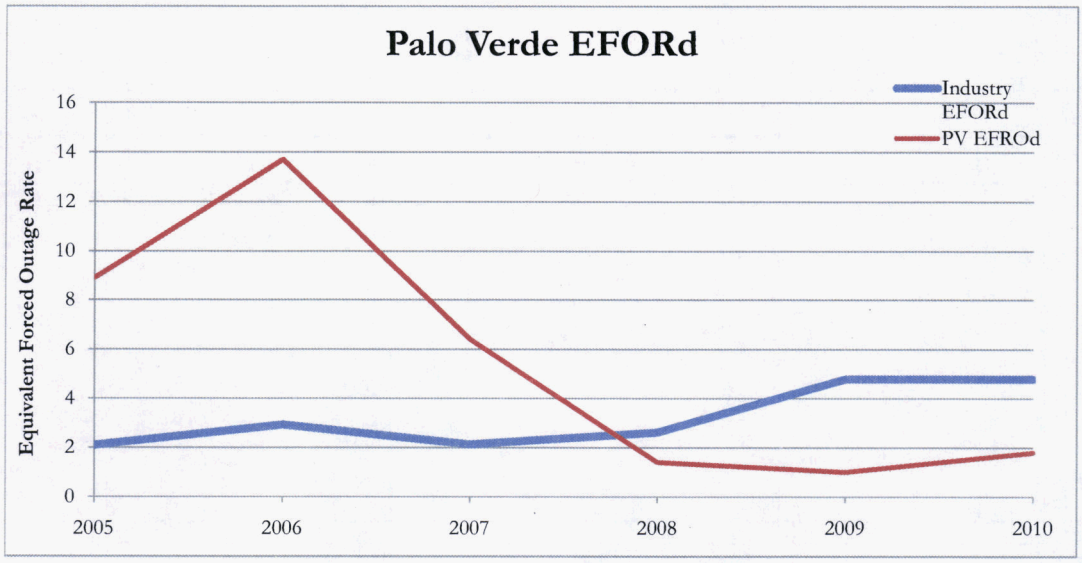
Employees per 1,000 Customers								
Company	**2010**	**2009**	**2008**	**2007**	**2006**	**2005**	**2004**	**Average**
DPL	2.74	2.90	2.87	2.82	2.59	2.48	2.61	2.72
NV Energy	2.44	2.59	2.79	2.77	2.79	2.86	2.99	2.75
NextEra Energy	3.31	3.41	3.39	3.19	2.98	2.83	2.82	3.14
Portland General	3.26	3.32	3.39	3.38	3.34	3.38	3.47	3.36
Westar Energy	3.51	3.51	3.56	3.45	3.34	3.33	3.23	3.42
Central Vermont Public Service	3.24	3.37	3.47	3.50	3.42	3.50	3.68	3.45
OGE	4.38	4.35	4.49	4.24	4.16	4.11	4.12	4.26
IDACORP	4.16	4.08	4.28	4.28	4.25	4.44	4.48	4.28
Great Plains Energy	3.87	3.89	3.97	4.94	4.91	4.78	4.91	4.47
Pinnacle West Capital - Adjusting for Employees at Jointly Owned facilities	*3.89*	*4.30*	*4.59*	*4.72*	*4.75*	*4.38*	*4.97*	*4.51*
Cleco Corp.	4.57	4.77	4.86	4.51	4.39	4.39	4.45	4.56
American Electric Power	4.37	5.08	5.15	4.92	4.86	4.72	4.82	4.84
Otter Tail Corp	5.22	5.35	5.39	5.23	5.08	5.04	5.07	5.20
Entergy	5.45	5.59	5.45	6.29	5.22	5.29	5.39	5.53
PNM Resources	4.25	4.31	5.78	6.38	6.87	7.24	6.45	5.90
Southern Company	5.88	5.93	6.20	6.13	6.08	6.04	6.14	6.06
Hawaiian Electric	7.70	7.80	8.09	8.03	7.97	9.58	9.61	8.40
Allete	8.94	9.11	9.54	9.34	9.43	9.56	9.33	9.32

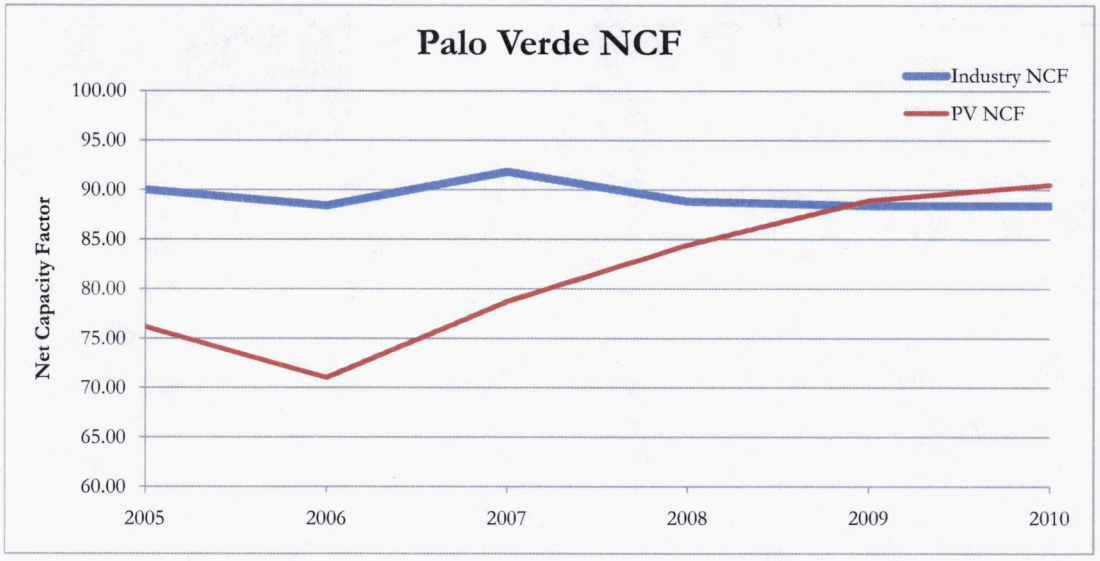
Salaries and Wages and Pensions and Benefits per Customer								
Company	**2010**	**2009**	**2008**	**2007**	**2006**	**2005**	**2004**	**Average**
NV Energy	0.14	0.17	0.14	0.14	0.14	0.14	0.15	0.15
NextEra Energy	0.18	0.17	0.16	0.17	0.16	0.15	0.13	0.16
Cleco Corp.	0.27	0.23	0.20	0.20	0.12	0.13	0.12	0.18
Entergy	0.20	0.17	0.17	0.22	0.19	0.16	0.16	0.18
American Electric Power	0.24	0.21	0.20	0.18	0.18	0.17	0.17	0.19
DPL	0.26	0.23	0.21	0.19	0.19	0.16	0.15	0.20
OGE	0.26	0.23	0.20	0.21	0.20	0.19	0.19	0.21
Portland General	0.23	0.22	0.22	0.22	0.21	0.19	0.18	0.21
Hawaiian Electric	0.00	0.10	0.34	0.33	0.30	0.23	0.26	0.22
Southern Company	0.25	0.23	0.25	0.25	0.26	0.25	0.24	0.25
PNM Resources	0.00	0.33	0.29	0.30	0.30	0.27	0.28	0.25
Westar Energy	0.31	0.30	0.27	0.26	0.24	0.23	0.21	0.26
IDACORP	0.24	0.29	0.26	0.27	0.27	0.26	0.27	0.27
Central Vermont Public Service	0.30	0.30	0.30	0.28	0.28	0.26	0.25	0.28
Pinnacle West Capital	*0.42*	*0.39*	*0.37*	*0.35*	*0.35*	*0.30*	*0.32*	*0.36*
Great Plains Energy	0.38	0.38	0.38	0.42	0.40	0.39	0.38	0.39
Otter Tail Corp	0.52	0.50	0.48	0.47	0.46	0.46	0.40	0.47
Allete	0.54	0.52	0.53	0.51	0.49	0.46	0.43	0.50

Source: SNL Financial, FERC Form 1, and SEC Form 10-K

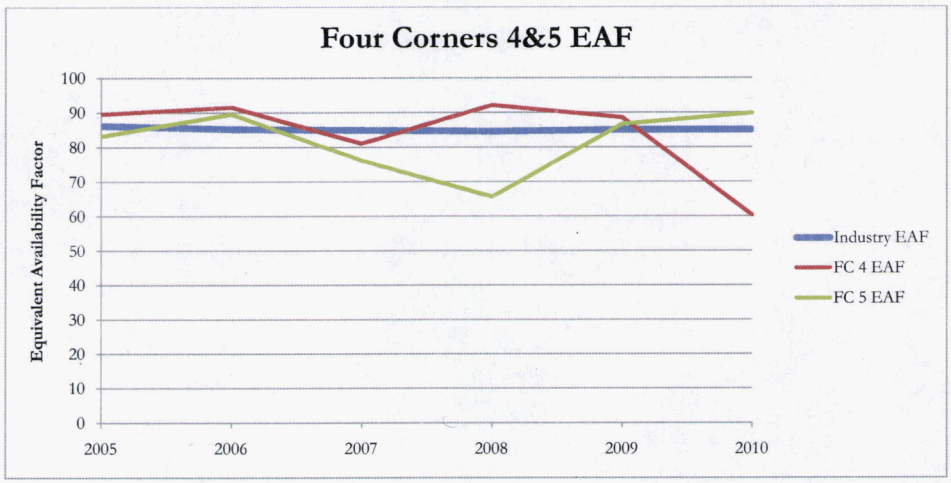
Nuclear Plant Metrics

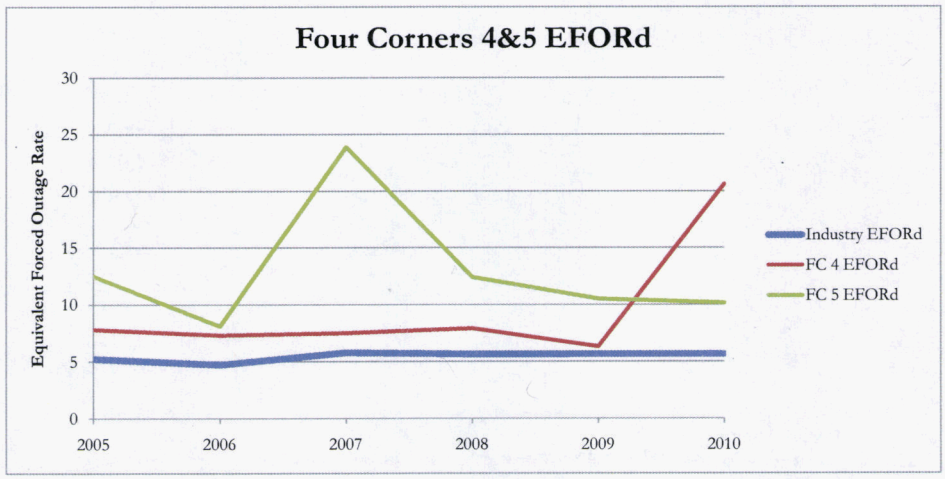


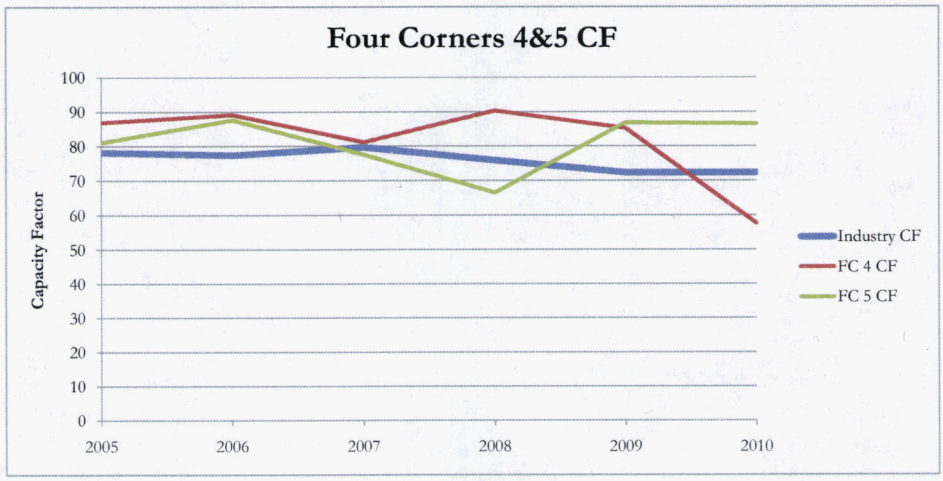




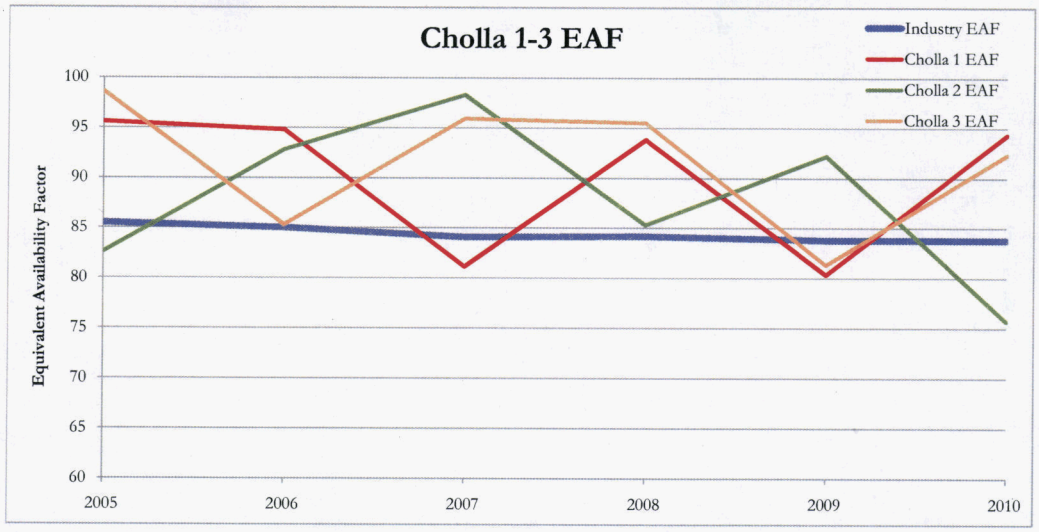
Fossil Plant Metrics

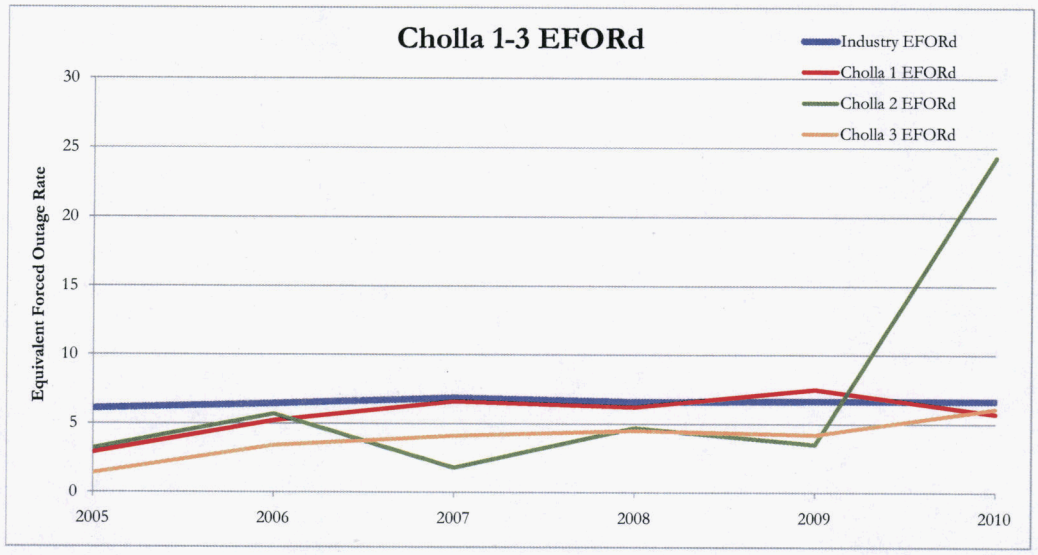


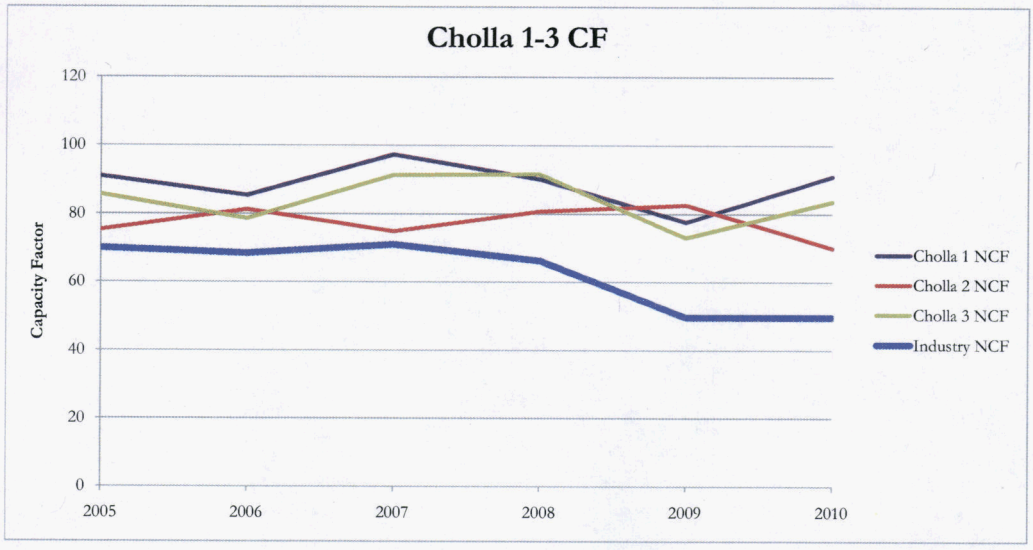




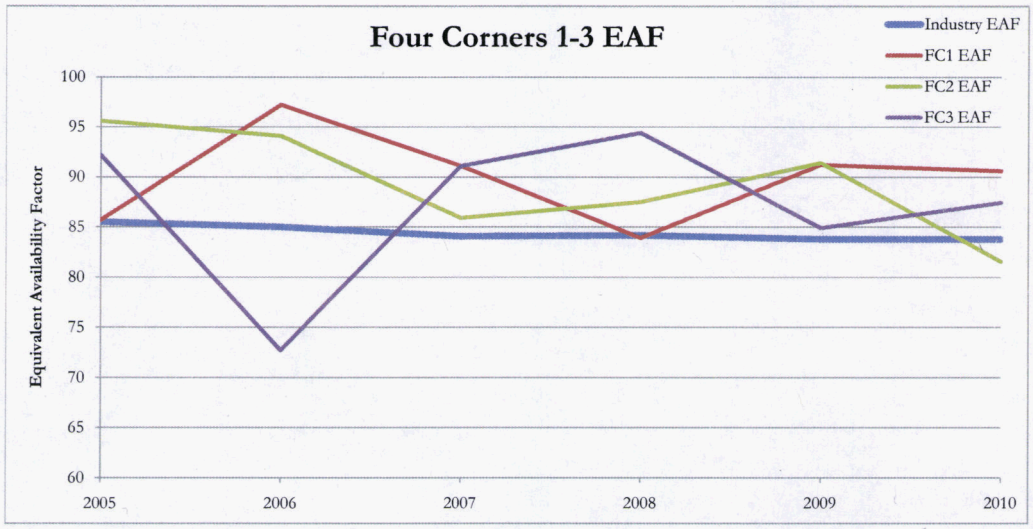
Fossil Plant Metrics

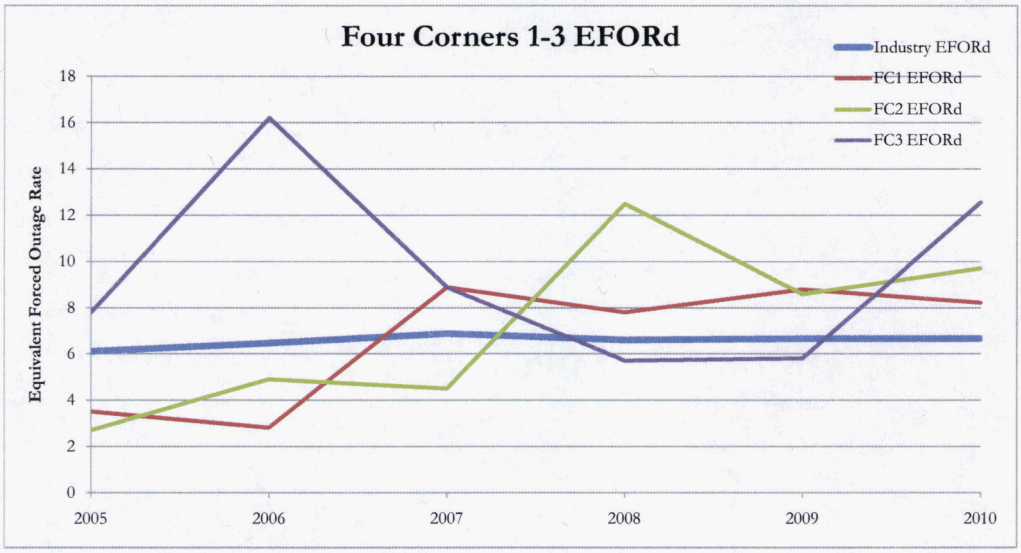


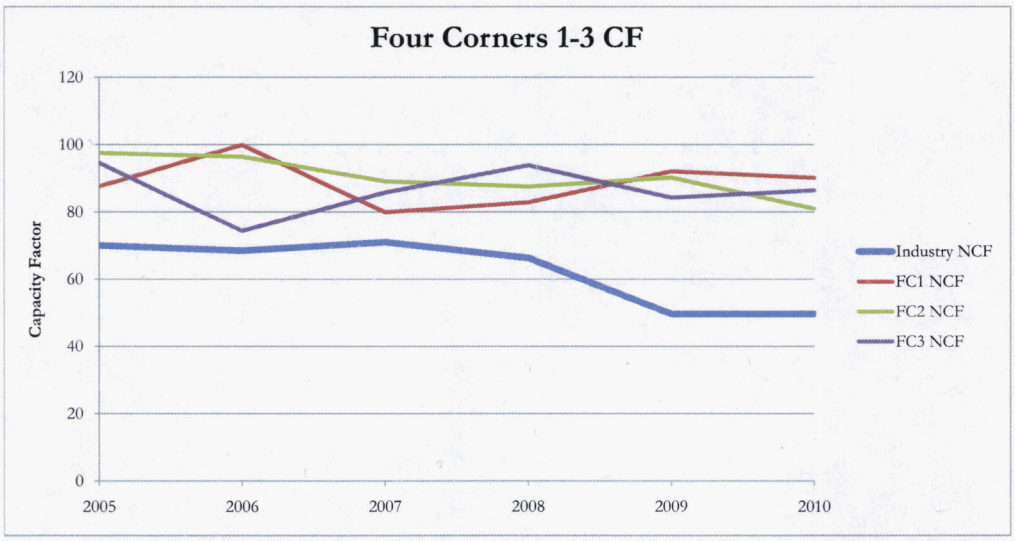




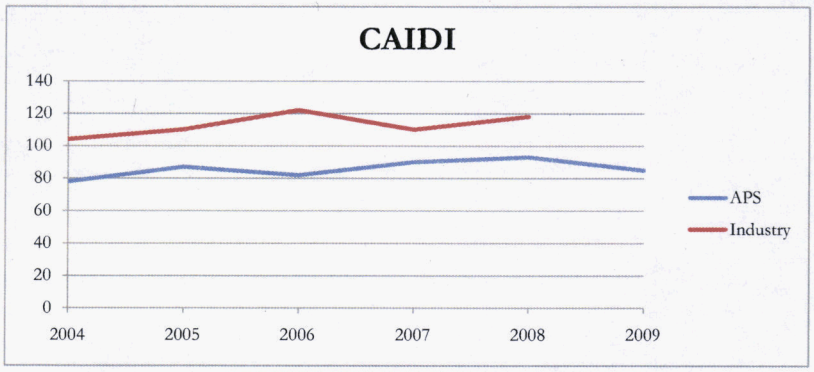
Fossil Plant Metrics

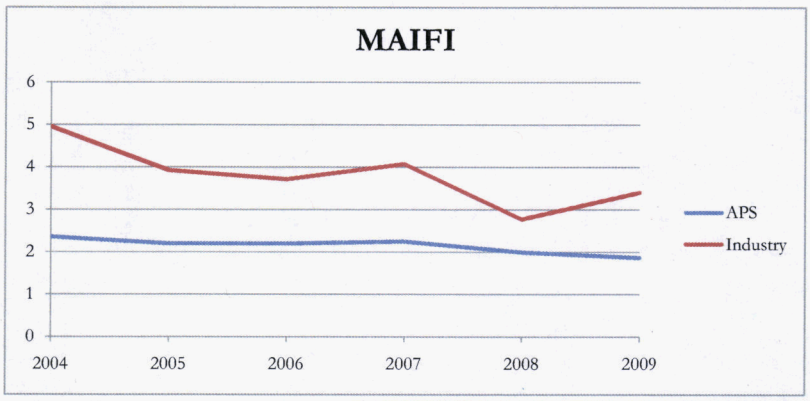


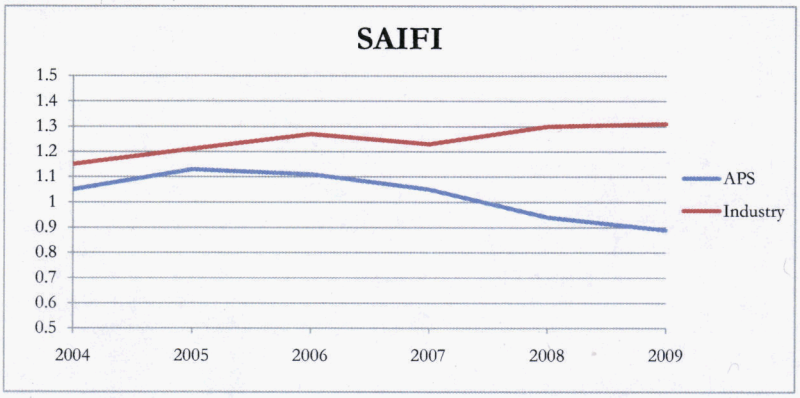


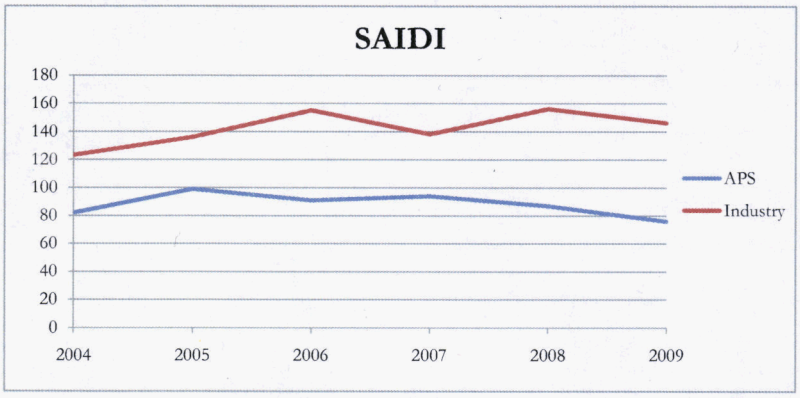


Distribution System Reliability Metrics









James R. Hatfield

TESTIMONY OF JAMES R. HATFIELD

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-____

June 1, 2011

Table of Contents

I. INTRODUCTION 1

II. SUMMARY. 2

III. THE POSITIVE MOMENTUM GENERATED BY THE SETTLEMENT AGREEMENT 4

IV. APS'S FINANCIAL CONDITION 9

V. PLAN TO MAINTAIN CREDIT RATINGS AND IMPROVE FINANCIAL METRICS 13

VI. KEY FORECASTED FINANCIAL RESULTS AND CONCLUSION 16

A. Summary Schedules 17

B. Cost of Capital 17

C. Projected Financial Information 18

VII. CONCLUSION. 19

Attachments

Generation and Distribution Capital Expenditure Reduction JRH-1

Generation and Distribution Capital Expenditure $30 Million Reduction JRH-2

Settlement Term Action Plan JRH-3

Projected Income Statements with Proposed Rate Increase JHR-4

TESTIMONY OF JAMES R. HATFIELD
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-____)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is James R. Hatfield. My business address is 400 North 5th Street, Phoenix, Arizona, 85004. I am Senior Vice President and Chief Financial Officer of both Arizona Public Service Company ("APS" or "Company") and Pinnacle West Capital Corporation ("Pinnacle West"). I have executive management responsibility for the financial affairs of the Company, including all aspects relating to accounting, finance, taxes, budgeting and financial planning, supply chain, enterprise risk and investor relations.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I have a Bachelor of Science degree with a functional major in accounting from Central Missouri State University and an M.B.A. degree from the University of Missouri-Kansas City. I have 31 years of experience in the utility and energy business. I joined APS and Pinnacle West in my current capacity in July 2008. Immediately prior to that time, from August 1994 until July 2008, I worked at OGE Energy Corp. ("OGE"), the parent company of Oklahoma Gas and Electric Company. While at OGE, I served in various roles, including Treasurer from August 1994 until January 1996, Vice President and Treasurer from January 1996 until November 1999, and Senior Vice President and Chief Financial Officer from November 1999 until July 2008. Before OGE, I worked in various accounting and finance roles at UtiliCorp United Inc. of Kansas City, Missouri from 1980 through 1994, and served as UtiliCorp's Assistant Treasurer from 1988 to 1993. From January through August of 1994, I also held the position of Vice President, Investor Relations and Corporate Secretary for Aquila Gas

Pipeline Corporation of San Antonio, Texas, a publicly traded subsidiary of UtiliCorp United Inc.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. My testimony will discuss the several benefits resulting from the regulatory framework established for APS by the 2009 Settlement Agreement ("Settlement" or "Settlement Agreement")[1], as well as explain why, because of the Settlement's financial design, APS is seeking a rate increase now. I also address APS's progress with respect to the "Settlement Term Action Plan" outlined in the Company's "Plan to Maintain Credit Ratings and Improve Financial Metrics" that APS filed on April 29, 2010 date in compliance with Section 8.4 of the Settlement. Finally, I sponsor the forecasted portions of Schedules A, D, and F that are included in the Company's rate application.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. This case offers the opportunity to further Arizona's energy policy objectives by continuing the positive momentum established in the Settlement Agreement to equip APS with the financial strength needed to provide safe and reliable service for APS customers during the second phase of the Settlement's five year plan term. The Settlement Agreement took an important step in the right direction for Arizona energy policy. It buttressed the Company's financial condition for the first of a two-phase Settlement period, and contained various provisions that began to modernize Arizona's historical regulatory structure as needed to put APS on a better financial standing with many investor-owned utilities throughout the country. These are companies against which APS competes for investment capital. Among other things, the Settlement Agreement placed APS on a rate case cycle, required important rate case process improvements aimed at

[1] Approved in Decision No. 71448 (December 30, 2009).

completing this and future cases in 12 months, and permitted the expedient collection of certain costs for APS-owned renewable projects. The Settlement led directly to a perceived improvement in APS' financial condition. The Company's bond ratings outlook improved and APS successfully completed a $253 million equity issuance last year on favorable terms, in a still tight economy.

But the Settlement Agreement was designed to support APS's financial metrics at agreed-upon levels through only the first phase of the 2010-2014 Settlement plan term ("Plan Term"). That initial phase is now coming to a close, and – as anticipated, and notwithstanding reductions in capital expenditures and operating costs made during and reflected in the Test Year at levels beyond what the Settlement requires – APS again faces Total Company projected returns on equity ("ROE") of 9.1% in 2012, 7.1% in 2013, and 6.7% in 2014. Returns like these are far below not only APS's 11% authorized ROE, but also the 10.6% average ROE actually earned in 2010 by other investor-owned utilities ("IOU") throughout the country. Without new rate relief that sustains APS's actual earned ROE at a reasonable level, APS will face challenges in raising the capital needed to invest in its system so as to provide safe and reliable electric service to APS customers and fulfill Arizona's efficiency, renewable energy, and other policy objectives.

My testimony also addresses the projected accounting data required by the Commission's SFRs to support the Company's rate case filing. Specifically, I sponsor the projected information presented on the following SFR Schedules:

- A-2 through A-5 – Summary Schedules
- D-1 through D-3 – Cost of Capital
- F-1 thru F-4 – Projected Financial Information

APS Witness Jason La Benz sponsors the historical and actual Test Year information required by those Schedules. APS Witness Zac Fryer jurisdictionalizes the Total Company data to isolate those items that fall within the Commission's regulatory jurisdiction.

III. THE POSITIVE MOMENTUM GENERATED BY THE SETTLEMENT AGREEMENT

Q. YOU INDICATED THAT THE SETTLEMENT AGREEMENT TOOK A STEP IN THE RIGHT DIRECTION FOR ARIZONA ENERGY POLICY. PLEASE EXPLAIN.

A. A key benefit of the Settlement Agreement is its outline of a modernized regulatory framework that enables APS to continue its superior operating performance and make investments in projects driven by energy policy, while easing the resulting rate impacts on customers gradually over time. It achieves this result by way of regulatory measures that tackle the root of the Company's subpar financial performance: rates that have not kept pace with the Company's capital expenditures, due in large part to regulatory lag.

APS's financial pressure is not caused by too much debt, operational inefficiency, or poor cost management. Rather, the primary cause of APS's substandard financial performance is that the rate making process in Arizona has been lengthy (often taking, for APS, as much as 18-24 months to resolve) and is based on a historical test year – conditions resulting in persistent regulatory lag.[2] Under such a regulatory model, the rates set in APS rate cases have historically been based on costs as much as three to five years old. In other words, even though APS's costs – like most people's – rise over time, the Company has generally been required to pay those higher costs with a revenue stream that is several years outdated.

[2] *See, e.g.,* Liberty Study at 41; Concentric report attached to the Testimony of Jeff Guldner at Attachment JBG-2.

Such a regulatory model deprives APS of the ability to charge rates that reflect its true cost of service. Inadequate rates, in turn, cause APS to be weak financially. APS's actual earned ROE has consistently fallen well below that of others in the industry for almost a decade. That remains true today: APS's earned an ROE of 9.3% in 2010, while others in the industry performed materially better. To cite just a few examples, in 2010, Southern California Edison earned a 13.2% return, Florida Power & Light earned 10.4%, Alabama Power Company earned 13.2%, Georgia Power earned 11.1%, and Oklahoma Gas & Electric Company earned 10.3%. Investors have little incentive to entrust their capital to a utility that offers below average returns, thus making it more difficult for APS to raise the capital needed to upgrade and maintain its system and progress Arizona's energy objectives. Weak financial metrics also expose APS to potential credit downgrades – an issue that has dominated APS's last few rate cases. Indeed, APS's credit rating is about one and a half credit notches below that of its industry peers, and while "[e]lectric utilities have generally experienced improved ratings since 2006[,] APS has not."[3]

Relying primarily on historical data inevitably results in more frequent rate filings, deterioration over time in APS's financial condition and difficulty in attracting capital. The result for APS has been a constant string of rate cases – a pattern that consumes the scarce resources of the Commission and other interested parties, distracts from the Company's ability to focus on operational matters and execution of policies, makes financing the significant infrastructure expenditures needed for system reliability and energy policy more difficult and costly for customers, and results in "lumpy" and unpredictable rate increases for APS customers.

[3] Liberty Study at 42.

Q. DID THE SETTLEMENT AGREEMENT ALLEVIATE THOSE CONSEQUENCES?

A. Yes, it made material progress. Key changes occurred when the Commission approved the Settlement Agreement, which took several important steps towards establishing a more supportive, modern regulatory construct. First, the Settlement placed APS on a "Rate Case Filing Plan" that governs APS rate applications until December 31, 2014.[4] By design, the Settlement Agreement permits APS to file two general rate cases during the five year Plan Term to address plant additions and other rate matters: one on June 1, 2011 (this case), and a second on or after June 1, 2013. To mitigate the cash flow-eroding impact of regulatory lag, the Settlement encourages that each of these cases be resolved within 12 months of a sufficiency finding and requires certain process improvements intended to facilitate that goal. As APS Witness Jeff Guldner explains, APS has worked hard with the other signatories to the Settlement Agreement to give life to those provisions and other process improvements in this case.

To provide an added measure of rate stability for customers, the Settlement prohibits APS from charging new base rates to customers until July of 2012 – two and a half years after the Company's last base rate increase. To fund the first phase of the Rate Case Filing Plan, the Settlement approved several regulatory tools specifically designed to support APS's financial performance in between the anticipated rate increases without too high of an upfront bill impact to customers. For example, recognizing the significant capital expenditures that APS had made beyond the 2007 Test Year and would make before Settlement rates would take effect in January 2010, the Agreement allowed APS to include in rate base certain (but not all) plant additions that the Company had made through June of 2009 –

[4] *See* Agreement at § 2.1.

18 months after the Test Year. The resulting rates did not compensate the Company fully for all capital expenditures made up to the rate-effective date and included no post-Test Year operating costs, and thus did not completely resolve regulatory lag. In fact, since 2007, APS has placed $594 million of plant in service that was not included in the prior post-Test Year Plant adjustment. Even so, there is no question that the adjustment was a strong move in the right direction.

The Settlement Agreement also authorized several other "bridge" mechanisms, equally necessary for APS to sustain financially the first phase of the Plan Term while mitigating the customer bill impact. These included the revenue treatment of the Company's line extension policy, the deferral of certain pension and OPEB costs, a depreciation rate change reflecting an anticipated license extension at Palo Verde, and a means by which APS can expediently collect carrying costs related to the Company's renewable energy investments.[5] The Settlement also required APS to eliminate expenses by a total of $150 million over the term of the Agreement.[6] Each of these provisions combined to close the gap between the Company's financial needs for the first phase of the Filing Plan and the maximum base rate increase the Settling Parties were willing to accept during a recession. Without these key financial benefits, APS would have been forced to file a rate case immediately after the conclusion of the last.

In combination, the Settlement's progressive regulatory tools allowed APS to continue to provide customers with superior electric service, invest in the Settlement's energy policy projects, and earn closer to its allowed ROE than it had for nine years. In doing so, the Settlement endowed APS and its stakeholders with the hope of a stronger, more constructive regulatory future and sustained

[5] *See* Agreement at §§ IX, X, XI, and XV.
[6] *See* Agreement at § VII.

financial improvement – a story that allowed Pinnacle West to raise $253 million of net equity capital in April of last year, which was invested into APS.

Q. PLEASE ELABORATE. HOW SPECIFICALLY DID THE FINANCIAL COMMUNITY REACT TO THE SETTLEMENT?

A. The reaction from equity analysts and credit rating agencies to the Settlement Agreement has been positive. Of greatest significance, on June 28, 2010, Standard & Poors Ratings Services ("S&P"), revised the Company's 'BBB-' bond rating outlook upward to "positive" from "stable," and changed APS's "business profile" to "excellent" from "strong."[7] According to S&P, the positive outlook reflects what it views as APS's "progress in managing its regulatory agenda as well as expense containment, which provides a platform for higher ratings contingent upon financial prudency entering the post-recession economy." In explaining the positive outlook, S&P specifically cited the Settlement's mitigation of regulatory lag:

> The business profile also reflects the success that APS has shown in managing regulatory risk. High customer growth has necessitated that the company file regular general rate cases to recover its investments and operating costs. The use of a historical test year in Arizona, coupled with the 18- to 24- month completion time for fully litigated rate cases, previously made it difficult for APS to earn authorized returns, but interim rates and the recovery of certain post-test year costs and a higher equity return in the latest rate case have reduced regulatory lag and should enhance financial performance.[8]

As a result, S&P announced that it could upgrade the Company's bond rating if APS is able to demonstrate sustained financial performance – a task that, S&P notes, may require APS to do what it can to "minimize[s] rate lag and promote[s] stability in financial performance" going forward.[9]

---

[7] *See* Research Update: Outlook on Pinnacle West Capital Corp. and Arizona Public Service Co. Ratings Revised to Positive; Ratings Affirmed, June 28, 2010.
[8] *Id.* at 3.
[9] *Id.* at 4.

Equity analysts similarly heralded the Settlement Agreement. Barclays, for example, described the Settlement as a "sea change" that "demonstrated a more constructive regulatory environment and significantly improved relationship with regulators."[10] Another analyst commented that "the regulatory/political environment in Arizona is beginning to better appreciate the damage that constant regulatory lag/attrition has inflicted on APS."[11]

Whether or not one agrees with these characterizations of Arizona's historical regulatory model, there is little doubt that the mechanisms approved with the Settlement made tangible progress toward a higher bond rating for APS. If APS is in fact upgraded – as we of course hope it will be – it will be because the rating agencies perceive Arizona as invested in the financial health of its largest utility and as willing to adapt its regulatory model to address the challenges that the Company, like the rest of the energy industry, faces today. With a 'BBB' credit rating, APS will have better access to capital at lower costs, will be able to continue to invest strongly in Arizona infrastructure and thereby promote job creation, and be more in step with the industry.

IV. APS'S FINANCIAL CONDITION

Q. GIVEN THE SUBSTANTIAL BENEFITS OF THE SETTLEMENT AGREEMENT, WHY DO YOU NEED A RATE INCREASE NOW?

A. Simply put, because the regulatory mechanisms put in place in the Settlement Agreement were not designed to sustain APS beyond 2012. The Post-Test Year Plant provision, while productive, included in rates most of the capital projects that APS had placed in service as of only June 1, 2009, seven months before the Settlement rates went into effect. It did not, however, include $594 million worth of plant investment that is now serving customers. Nor did it include the

[10] "Raising Arizona," Barclays (Dan Ford), June 24, 2010.
[11] "Raising Rating, Target, Estimates," Wellington Shields and Company (Chris Ellinghaus), June 4, 2010.

additional $959 million of new plant that will be in service by the anticipated July 1, 2012 rate effective date.

Other of the Settlement's financially supportive provisions will also quickly expire. The Settlement provision that allows APS to defer, at most, $42.5 million of pension and OPEB costs in 2011 and 2012 terminates next year. The revenue treatment of line extension proceeds, which was lower than anticipated due to the slowdown in new growth in any event, also falls off at the earliest of the end of this rate case or the end of 2012. And although the Settlement allows APS to reduce its depreciation expense starting January 1, 2012 to reflect the license extension recently granted for Palo Verde on April 22, 2011, that benefit alone is insufficient to sustain the Company throughout the remainder of the Plan Term under present base rates.

In fact, notwithstanding substantial cost containment measures underway, the Company's actual earned ROE dips again during the second phase of the Settlement term to the mid-single digit ranges typical of pre-Settlement days. On a Total Company basis, APS expects to actually earn in 2011 an ROE of 8.8%, a number that grows to 9.1% in 2012 (the last year in which APS receives Settlement-related rate benefits), but then falls to 7.1% in 2013 and 6.7% in 2014 (the earliest year in which the second general rate case authorized by the Agreement would likely conclude). These returns fall off in the later years because of the material capital investments required. Without rate relief, the returns in the latter years are at levels similar to or below what APS was facing when this Commission authorized interim rate relief for the Company in 2009 – mid-range single digits described by the financial world as "abysmal."[12] APS's

[12] Credit Suisse, Equity Research, March 10, 2009.

FFO to Debt levels also deteriorate during this time, falling to 18.3% in 2013 (versus 2010's 21.4% levels).

Such metrics would eradicate any chance of S&P upgrading APS to a solid 'BBB' during the Settlement term. They would also limit APS's ability to secure the capital needed to invest in safety, reliability, customer service, efficiency, renewable, and other energy policy projects, and would make any such capital more expensive for customers. Further, with such metrics, the Company would not likely be able to raise the equity capital needed both to maintain a balanced capital structure and to meet sections 8.1 through 8.3 of the Settlement Agreement.[13] It was for these very reasons that the Settlement Agreement, recognizing that the Company would have incremental revenue needs in 2011, allowed APS to file a rate case at this time.

Q. CAN THE COMPANY ACHIEVE ITS FINANCIAL NEEDS THROUGH FURTHER COST CUTTING?

A. No. APS simply cannot cut enough costs to earn even close to its authorized rate of return without significantly sacrificing reliability and service quality. As described in the testimonies of APS President Don Robinson and others, APS has undertaken a significant cost management initiative, cutting more than $37 million in expenses during the Test Year. But despite these significant cost-management efforts, and taking full account of the additional expense reductions the Settlement requires, APS still has an annual ACC-jurisdictional revenue requirement deficiency of $129 million for 2012, $233 million for 2013, and $286 million for 2014. As shown in JRH-1, APS would have to reduce generation and distribution capital spend by more than $400 million per year

[13] Section 8.1 of the Agreement requires APS "to complete equity infusions of at least $700 million during the period from June 1, 2009 through December 31, 2014." Section 8.3 requires that APS "use its best efforts to improve its financial metrics and bond ratings, by completing timely equity infusions and taking other measures to strive to achieve a capital structure with no more than 52% debt/total capital as calculated by the ratings agencies, by December 31, 2012."

($1.6 billion for 2011 through 2014) in order to close this gap through capital reductions alone. Even if the Company were to reduce expenses by an additional $30 million per year beyond the Settlement's mandate (which it cannot do without a significant and inadvisable reduction in our current workforce, an act that would put into question APS's ability to maintain reliability and achieve a sustainable energy future), the Company would still have to cut capital expenditures by $350 million per year through 2014 to make up the deficiency. *See* JRH-2.

To address this deficiency on the expense side rather than the revenue side would mean eliminating projects that are vital to APS's basic service obligations, projects such as those described by APS Witnesses Randy Edington, Mark Schiavoni, and Daniel Froetscher. APS certainly would not want to risk sacrificing reliability in order to improve its financial condition, and highly doubts that its customers or the Commission would want it to do so either.

Q. DOES THE COMPANY HAVE TOO MUCH DEBT ON ITS BALANCE SHEET? PLEASE EXPLAIN.

A. No, it does not. APS's capital structure reflects an appropriate balance of debt and equity capital. In fact, as of the end of the 2010 Test Year, APS had less long-term debt on its balance sheet than was average for similar IOUs across the country. As Schedule D-1 reflects, in 2010, the Company's balance sheet long-term debt to total capitalization ratio was 46%. This metric compares favorably to an average 2010 long-term debt to total capitalization ratio of over 49% for similar investor owned utilities. Importantly, APS's net cash flow from operations to long-term debt was also below average: 21% for APS compared to 24% for the peer group. In other words, APS has less cash-flow available to service its debt than is average – a deficiency on the revenue side, not the debt side.

V. PLAN TO MAINTAIN CREDIT RATINGS AND IMPROVE FINANCIAL METRICS

Q. ON APRIL 29, 2010, APS FILED A "PLAN TO MAINTAIN CREDIT RATINGS AND IMPROVE FINANCIAL METRICS." IS APS ON TRACK WITH THAT PLAN?

A. Yes. The "Settlement Term Action Plan," attached to my testimony as JRH-3, expressed three objectives as the Company's focus during the Settlement's plan term: (1) to maintain an earned ROE of around 9% in 2010 and 2011, and work to earn closer to its authorized 11% ROE in the subsequent years; (2) to manage its FFO/Debt ratio and capital structure to comply with the terms of Sections 8.2 and 8.3 of the Agreement; and (3) to continue to highlight to credit rating agencies the positive developments in Arizona's regulatory environment, which is the qualitative consideration that S&P declares "the most important factor in [its] analysis of a U.S. regulated, investor-owned utility's business risk."[14] To achieve those objectives, APS outlined five strategies: (1) maintain a balanced capital structure and infuse equity as appropriate; (2) mitigate negative impacts of debt imputation; (3) focus on cost management; (4) pursue rate-related strategies for timely cost recovery; and (5) support the capital markets' evolving perception of Arizona's regulatory environment and other qualitative factors.

The Company is on target with respect to each facet of its plan. As to the first strategy, APS generally aims to maintain a capital structure with a ratio of roughly 54% equity and 46% long-term debt, which we believe is an appropriate balance. This is also consistent with the capital structure filed in this case: APS's capital structure is composed of 46.06% debt and 53.94% equity. This ratio reflects the infusion of $253 million of equity into the Company by Pinnacle West in April/May of 2010, the first tranche of APS's commitment to receive a total of $700 million of equity infusions through December 31, 2014. APS has

[14] *See "Assessing U.S. Utility Regulatory Environments,"* Global Credit Portal, Ratings Direct (March 11, 2010).

issued no new debt since the execution of the Settlement Agreement, but will continue to raise debt capital to fund maturing debt and finance capital investment as market conditions permit and capital needs arise. APS plans to issue or obtain such new debt and equity financing to fund its capital requirements while maintaining a balanced capital structure throughout the Settlement Term.

With respect to the second strategy, APS is working hard to manage the impact of imputed debt on its credit metrics and achieve the 52% adjusted debt/adjusted total capital ratio that the Settlement encourages. *See* Agreement at § 8.3. For example, to mitigate the negative imputed debt impact of Purchase Power Agreements ("PPAs"), APS is actively pursuing ownership of renewable power plants so that it can meet the renewable energy requirements of the Settlement and avoid further PPA-related debt imputation. To date, APS has contracted for 83 megawatts of renewable energy under its AZ Sun program, and will balance investments in new utility-owned renewable generation resources and procurement through PPAs as appropriate to achieve our renewable energy commitments throughout the Plan Term.

In addition, because of a recent change in accounting standards (FAS 167), APS now reflects the debt and equity components of APS's Palo Verde Unit 2 sale leaseback obligations on its balance sheet, rather than as imputed debt. APS also made a voluntary contribution to its pension plan of $200 million in 2010, which improved the funded status of the plan and reduced the associated debt imputation. Because of these and other efforts, as of the end of the 2010 test year, APS's adjusted debt/adjusted total capitalization ratio was 54.4%, down from 57.2% as of the end of 2008, as calculated by the Company's approximation of S&P's bond benchmark methodology.

The third prong of APS's Plan to Maintain Credit Ratings and Improve Financial metrics is to focus on cost management. As previously indicated, APS has undertaken a significant cost management initiative, exceeding the minimum level for 2010 required by Section 7.1 of the Settlement. That Company-wide undertaking is described by Don Robinson in his testimony, and examples of savings by business unit are described in greater detail in the testimonies of Daniel Froetscher (for Energy Delivery), Mark Schiavoni (for Fossil Generation), and Randy Edington (for Nuclear Generation). APS's cost management focus is also detailed in a letter from Don Robinson to Docket Control filed with the Commission on April 29, 2011 in Docket No. E-01345A-08-0172.

Fourth, APS is actively pursuing rate-related strategies for timely cost recovery, as demonstrated by the present rate application. As described above, timely, adequate rate relief is critical for APS to achieve its financial objectives. Towards that end, and as APS Witness Jeff Guldner discusses in his testimony, APS has engaged its stakeholders and Commission Staff to develop a process that will allow the case to resolve with rates effective within 12 months of a sufficiency finding. In addition, and as noted previously in my testimony, APS requests in this filing various rate tools that will modernize the APS rate structure and reduce the detrimental financial impact of regulatory lag in a historical test year cost of service model.

The final piece of APS's Plan is to support the capital market's evolving perception of Arizona's regulatory environment and other qualitative factors. Our progress in this realm is in two parts: first, to pursue a regulatory construct that will be viewed as positive by the financial markets; and second, to communicate that story and show that Arizona supports the financial performance and credit quality of its utilities. Our success in this effort to date is exemplified

by the positive remarks contained in rating agency and equity analyst articles that have been published since the Settlement Agreement, virtually all of which focus on Arizona's marked demonstration of collaboration and commitment to processing rate cases faster with a more financially supportive result than has historically been the case. The Commission's policy statement on decoupling and support of the Company's AZ Sun projects were also positively received.

While the rating agencies have indicated their intent to keep a watchful eye on APS during this rate proceeding, the industry's expectations are high and the shift in the historical perception that Arizona is a "challenging" regulatory environment is a cautious one. Without timely and adequate rate relief from this case, that perception would instantly sour.

VI. KEY FORECASTED FINANCIAL RESULTS AND CONCLUSION

Q. PLEASE DESCRIBE THE ACCOUNTING INFORMATION CONTAINED WITHIN THE SFR SCHEDULES THAT YOU ARE SPONSORING.

A. With respect to the Company's SFR schedules, my testimony covers the forecasted accounting statements and financial results. The Total Company data is the same type of information that is disclosed directly or indirectly in both the APS and the consolidated Pinnacle West audited financial statements, each of which are included in filings made with the SEC for historical years. The forecasted information periodically is supplied to investors and filed with the SEC.

Additionally, all of the accounting projections provided in my testimony follow Generally Accepted Accounting Principles ("GAAP"). These are the principles that accounting professionals use to prepare financial statements. One major goal of GAAP is to make financial statements comparable from year to year, from industry to industry, and from jurisdiction to jurisdiction. In addition to GAAP,

APS's accounting practices comply with other applicable utility accounting standards, such as the FERC Uniform System of Accounts, which this Commission has adopted. *See* AAC R14-2-212(G).

The Direct Testimony of APS Witness Jay La Benz addresses the historical accounting statements and actual Test Year data used in the SFRs. Zac Fryer focuses on the jurisdictional allocation of APS revenues, costs and rate base items for the actual Test Year and all the pro forma adjustments.

A. Summary Schedules

Q. PLEASE DESCRIBE THE PROJECTED INFORMATION ON SFR SCHEDULES A-2 THRU A-5.

A. These summary schedules provide the "Summary Results of Operations," the "Summary Capital Structure," the "Construction Expenditures, Net Plant Placed in Service and Gross Utility Plant in Service," and the "Summary Changes in Financial Position" for the Test Year and the prior two calendar years. These schedules also include historical information. I am sponsoring the forecasted data for the Test Year and future calendar years. Mr. La Benz is sponsoring the historical information on these schedules. As Line 12 of Schedule A-2 shows, if the Company's rate request is granted effective July 1, 2012, Total Company average ROE will be 10.0% at December 31, 2012 (a year in which new rates will have been in effect for only six months) and 9.7% at 2013.

B. Cost of Capital

Q. PLEASE DISCUSS THE COST OF CAPITAL INFORMATION THAT YOU ARE SPONSORING.

A. SFR Schedule D-1 is the summary of the Company's historical and projected cost of capital. I am sponsoring the forecasted data in this schedule. SFR Schedule D-2 presents supporting detail for the long-term debt summarized on SFR Schedule D-l. Again, I sponsor the projected data in this schedule. SFR Schedule D-3 addresses preferred stock. Although the Company did not have

any outstanding preferred stock as of the end of the Test Year, it has included Schedule D-3 nonetheless for the sake of completeness. SFR Schedule D-4 addresses the Company's cost of common equity, and is sponsored by Mr. La Benz.

C. Projected Financial Information

Q. PLEASE DISCUSS THE INFORMATION THAT YOU ARE SPONSORING ON SFR SCHEDULES F-1 THROUGH F-4.

A. SFR Schedule F-1 presents income statements for projected calendar years, and for actual Test Year results, at present and proposed rates. I sponsor the projected information contained on these schedules, while Mr. La Benz sponsors the historical and actual Test Year information.

As I have previously indicated, Schedule F-1, like Schedule A-2, shows key information relating to the Company's actual and projected ROE. As Schedule F-1 shows, under APS's present rates, the Company's ROE falls from 9.3% at the end of the Test Year to 8.8% at year end 2011, grows to 9.1% in 2012 (the last year in which we receive Settlement-related rate benefits), then falls to 7.1% 2013—well below any reasonable ROE required to maintain the financial health of APS and ensure access to capital necessary for a robust electric system. The Company's proposed rates would bring the Company's ROE to 10.0% in 2012 and 9.7% by year end 2013. As JRH-4 shows, the calculated ROE improves when considering only those items that fall within the Commission's regulatory jurisdiction, partly because the ACC-jurisdictional analysis removes all of the Company's below the line expenses.

SFR Schedule F-2 shows projected changes in the financial position of the Company for future calendar years and the Test Year, at present and proposed rates. SFR Schedule F-3 presents projected annual construction requirements, by property classification, for four years subsequent to the Test Year. I sponsor the

projected data on this schedule. Finally, SFR Schedule F-4 presents the key assumptions used in developing projections.

VII. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. APS hopes to continue working with the Commission and other stakeholders achieve a strong energy future for Arizona. However, it is quickly losing the financial support provided by the first phase of the Settlement term that allows it to do so. To continue down this path, APS will need rate relief adequate to compensate it for the significant amount of capital that has been and will be invested in the business. What is unique to APS and other Arizona utilities compared to others in the industry is the lower use of modernized rate tools that reduce the detrimental impact of regulatory lag and maintain the Company's financial condition in between rate cases. APS seeks the Commission's authorization to implement some of those tools in this Application, thus smoothing rate increases for customers and allowing APS and the Commission to avoid the distraction of a constant string of rate cases and to focus instead on refining important energy policies that will shape this State's future.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Necessary Generation and Distribution Capital Reductions Needed to Correct Revenue Deficiency if Present ACC Base Rates Continue

($ in Millions)

Line #		2011	2012	2013	2014	Cumulative
	Projected revenue deficiency:					
1	Projected APS shareholder net income	$ 301.4	$ 324.1	$ 259.5	$ 243.2	
2	Projected year-end common equity	$ 3,154	$ 3,427	$ 3,408	$ 3,555	
3	Return on common equity	9.6%	9.5%	7.6%	6.8%	
4	Allowed ROE	11.00%	11.00%	11.00%	11.00%	
5	Net income at allowed ROE (line 2 x line 4)	347	377	375	391	
6	Net Income over / (under) allowed ROE (line 1 - line 5)	$ (46)	$ (53)	$ (116)	$ (148)	$ (363)
7	Revenue conversion factor	1.6532	1.6532	1.6532	1.6532	
8	Annual revenue deficiency excluding fair value	$ (76)	$ (88)	$ (192)	$ (245)	$ (601)
9	Fair value revenue requirement in 2010 test year	$ (41)	$ (41)	$ (41)	$ (41)	
10	Annual revenue deficiency including fair value	$ (117)	$ (129)	$ (233)	$ (286)	$ (765)
	Revenue requirement impacts of reducing capital expenditures:					
11	2011 Capital expenditure reductions	(400)	(400)	(400)	(400)	
12	2012 Capital expenditure reductions		(400)	(400)	(400)	
13	2013 Capital expenditure reductions			(400)	(400)	
14	2014 Capital expenditure reductions				(400)	
15	Total capital expenditure reductions	(400)	(800)	(1,200)	(1,600)	
16	Book depreciation savings	3%	3%	3%	3%	
17	Property tax savings	1%	1%	1%	1%	
18	Interest and equity return savings (1)	9%	9%	9%	9%	
19	Income tax savings (1)	4%	4%	4%	4%	
20	Revenue requirements savings as a % of capital expenditure reductions	17%	17%	17%	17%	
21	Annual revenue requirement reduction (line 15 x line 20)	(68)	(136)	(204)	(272)	(680)
22	Remaining annual revenue deficiency (line 10 - line 21)	$ (49)	$ 7	$ (29)	$ (14)	$ (85)

(1) Assuming the Company's proposed cost of capital with a 53.94% equity ratio and an 11% allowed return on common equity

Necessary Generation and Distribution Capital Reductions Needed to Correct Revenue Deficiency if Present ACC Base Rates Continue and a Reduction of $30 Million in O&M is Required

($ in Millions)

Line #		2011	2012	2013	2014	Cumulative
	Projected revenue deficiency:					
1	Projected APS shareholder net income	$ 301.4	$ 324.1	$ 259.5	$ 243.2	
2	Projected year-end common equity	$ 3,154	$ 3,427	$ 3,408	$ 3,555	
3	Return on common equity	9.6%	9.5%	7.6%	6.8%	
4	Allowed ROE	11.00%	11.00%	11.00%	11.00%	
5	Net income at allowed ROE (line 2 x line 4)	347	377	375	391	
6	Net Income over / (under) allowed ROE (line 1 - line 5)	$ (46)	$ (53)	$ (116)	$ (148)	$ (363)
7	Revenue conversion factor	1.6532	1.6532	1.6532	1.6532	
8	Annual revenue deficiency excluding fair value	$ (76)	$ (88)	$ (192)	$ (245)	$ (601)
9	Fair value revenue requirement in 2010 test year	$ (41)	$ (41)	$ (41)	$ (41)	
10	Annual revenue deficiency including fair value	$ (117)	$ (129)	$ (233)	$ (286)	$ (765)
10a	Assume another $30m of required O&M reductions	$ 30	$ 30	$ 30	$ 30	$ 120
10b	Adjusted annual revenue deficiency	$ (87)	$ (99)	$ (203)	$ (256)	$ (645)
	Revenue requirement impacts of reducing capital expenditures:					
11	2011 Capital expenditure reductions	(350)	(350)	(350)	(350)	
12	2012 Capital expenditure reductions		(350)	(350)	(350)	
13	2013 Capital expenditure reductions			(350)	(350)	
14	2014 Capital expenditure reductions				(350)	
15	Total capital expenditure reductions	(350)	(700)	(1,050)	(1,400)	
16	Book depreciation savings	3%	3%	3%	3%	
17	Property tax savings	1%	1%	1%	1%	
18	Interest and equity return savings (1)	9%	9%	9%	9%	
19	Income tax savings (1)	4%	4%	4%	4%	
20	Revenue requirements savings as a % of capital expenditure reductions	17%	17%	17%	17%	
21	Annual revenue requirement reduction (line 15 x line 20)	(60)	(119)	(179)	(238)	(596)
22	Remaining annual revenue deficiency (line 10b - line 21)	$ (27)	$ 20	$ (24)	$ (18)	$ (49)

(1) Assuming the Company's proposed cost of capital with a 53.94% equity ratio and an 11% allowed return on common equity

APS ORIGINAL

ARIZONA PUBLIC SERVICE

Susan Casady
Regulatory Programs Leader
State Regulation

Tel. 602-250-2709
Fax 602-250-3003
e-mail Susan.Casady@aps.com

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

April 29, 2010

Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

RE: Arizona Public Service Company 2008 Amended Rate Case
Plan to Maintain Credit Ratings and Improve Financial Metrics
E-01345A-08-0172, Decision No. 71448

Pursuant to Arizona Public Service Company's ("APS") Settlement Agreement approved in Decision No. 71448, APS was ordered to submit the following:

> Section 1.16(d): "a plan to be prepared by APS to maintain investment grade financial ratios and improve APS' financial metrics."
>
> Section 8.4: "prepare and submit to the [Arizona Corporation] Commission and Signatories within 120 days of approval of the Agreement, a plan detailing steps it intends to take to maintain and improve its financial ratings with the credit rating agencies."
>
> Section 13.2(g): "submit a plan to the Commission to maintain investment grade financial ratios and to improve financial metrics."

In fulfillment of each of these provisions, APS has prepared and hereby submits the following plan to maintain the Company's credit ratings and improve financial metrics.

If you have any questions regarding this information, please contact Zachary Fryer at (602) 250-4167.

Sincerely,

Susan Casady

Susan Casady

SC/sl
Attachment
cc: Steve Olea
Brian Bozzo
Barbara Keene
Terri Ford
Parties of Record

Arizona Corporation Commission
DOCKETED
APR 29 2010
DOCKETED BY

RECEIVED
2010 APR 29 P 4: 21
AZ CORP COMMISSION
DOCKET CONTROL

Copies of the foregoing delivered/mailed
this 29th day of April, 2010, to:

Ernest G. Johnson
Arizona Corporation Commission
1200 West Washington Street
Phoenix , AZ 85007

Maureen Scott
Arizona Corporation Commission
1200 West Washington Street
Phoenix , AZ 85007

Janet Wagner
Arizona Corporation Commission
1200 West Washington Street
Phoenix , AZ 85007

Terri Ford
Arizona Corporation Commission
1200 West Washington Street
Phoenix , AZ 85007

Barbara Keene
Arizona Corporation Commission
1200 West Washington Street
Phoenix , AZ 85007

Daniel Pozefsky
RUCO
1110 West Washington
Suite 220
Phoenix , AZ 85007

William A. Rigby
RUCO
1110 West Washington
Suite 220
Phoenix , AZ 85007

Tina Gamble
RUCO
1110 West Washington
Suite 220
Phoenix , AZ 85007

C. Webb Crocket
Fennemore Craig
3003 North Central
Suite 2600
Phoenix , AZ 85012

Kevin Higgins
Energy Strategies, LLC
215 South State Street
Suite 200
Salt Lake City, UT 84111

Michael L. Kurtz
Boehm, Kurt & Lowry
36 East Seventh Street
Suite 2110
Cincinnati, OH 45202

Kurt J. Boehm
Boehm, Kurt & Lowry
36 East Seventh Street
Suite 2110
Cincinnati, OH 45202

Dennis George
The Kroger Company
1014 Vine Street
Cincinnati, OH 45202

Stephen J. Baron
J. Kennedy & Associates
570 Colonial Park Drive
Suite 305
Roswell, GA 30075

Theodore Roberts
Sempra Energy
101 Ash Street
H Q 13D
San Diego, CA 92101

Lawrence V. Robertson, Jr.
2247 E. Frontage Road
Tubac, AZ 85646

Michael A. Curtis
501 East Thomas Road
Phoenix , AZ 85012

William P. Sullivan
501 East Thomas Road
Phoenix , AZ 85012

Larry K. Udall
501 East Thomas Road
Phoenix , AZ 85012

Michael Grant
Gallagher & Kennedy, P.A.
2575 East Camelback Road
Phoenix , AZ 85016

Gary Yaquinto
Arizona Investment Council
2100 North Central
Suite 210
Phoenix , AZ 85004

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

Tim Hogan
Arizona Center for Law in the Public Interest
202 East McDowell Road
Suite 153
Phoenix , AZ 85004

Jeff Schlegel
SWEEP Arizona Representatives
1167 W. Samalayuca Drive
Tucson, AZ 85704

Jay I. Moyes
Moyes, Sellers & Sims
1850 North Central Avenue
Suite 1100
Phoenix , AZ 85004

Jeffrey J. Woner
K.R. Saline & Associates, PLC
160 N. Pasadena
Suite 101
Mesa, AZ 85201

Scott Canty
The Hopi Tribe
P.O. Box 123
Kykotsmovi, AZ 86039

Cynthia Zwick
1940 E. Luke Avenue
Phoenix , AZ 85016

Nicholas J. Enoch
349 North 4th Avenue
Phoenix , AZ 85003

Karen S. White
AFLOA/JACL-ULT
139 Barnes Drive
Tyndall AFB, FL 32403

Douglas V. Fant
Law Offices of Douglas V. Fant
3655 W. Anthem Drive
Suite A-109 PMB 411
Anthem, AZ 85086

Barbara Wyllie-Pecora
27458 N. 129th Drive
Peoria, AZ 85383

Carlo Dal Monte
Catalyst Paper Corporation
65 Front Street
Suite 201
Nanaimo, BC 0

Steve Morrison
SCA Tissue North America
14005 West Old Hwy 66
Bellemont, AZ 86015

Arizona Public Service Company

Plan to Maintain Credit Ratings and Improve Financial Metrics

Compliance Filing, Decision No. 71448, Docket No. E-01345A-08-0172

April 29, 2010

APS

Arizona Public Service Company
Plan to Maintain Credit Ratings and Improve Financial Metrics

Executive Summary

Arizona Public Service Company's ("APS" or "Company") current credit ratings are "BBB-" from Standard & Poor's ("S&P"), "Baa2" from Moody's Investors Service ("Moody's"), and "BBB" from Fitch Ratings ("Fitch"), all of which currently classify those ratings as "stable." The Company's ultimate credit rating objective is to improve or maintain its ratings to at least the mid-BBB level or its equivalent, if not better, at all three of the ratings agencies. Doing so would permit APS to borrow at more favorable interest rates and enhance its ability to reliably access the capital markets, while also providing greater protection from a non-investment grade rating – outcomes that benefit customers and APS alike. Such an improvement, however, will take time because the ratings agencies ultimately look for stability and predictability in credit quality – characteristics that can take several years to demonstrate.

A change to APS's credit rating can be accomplished by improving the Company's financial metrics, improving the underlying risk profile (what S&P calls "business position"), or a combination of both. APS's Plan to Maintain Credit Ratings and Improve Financial Metrics ("Plan") focuses on enhancing the Company's financial metrics (such as ROE and FFO/Debt) wherever practicable, and advocating that the ratings agencies recognize the improvements in our underlying risk profile.

The most critical qualitative factor that all the ratings agencies consider when rating investor-owned utilities is the extent to which the regulatory environment provides timely and full cost recovery. The Arizona Corporation Commission's ("Commission") approval of the Company's recent Settlement Agreement ("Agreement") provided a platform that improved APS's earned returns on equity and financial performance and established a rate case filing schedule with process improvements, and was thus viewed by the ratings agencies as a positive development in APS's regulatory environment. Other regulatory

decisions, such as the Commission's approval of APS's AZ Sun program and the Federal Energy Regulatory Commission's ("FERC") approval of transmission formula rates for APS, also provide positive support for this aspect of the ratings agencies' analysis.

Against this important backdrop, this Plan outlines APS's key strategies to maintain its credit ratings and improve its financial metrics: managing the capital structure, primarily through well-planned debt and equity issuances; taking measures to reduce negative effects of imputed debt; effectively managing costs across the Company; and advocating for recognition of a positive qualitative change in the Company's risk profile. Each is discussed in greater detail herein.

Arizona Public Service Company
Plan to Maintain Credit Ratings and Improve Financial Metrics

Introduction

Section 8.4 of APS's Agreement, approved in Decision No. 71448 (December 30, 2009), requires APS to "prepare and submit to the [Arizona Corporation] Commission and Signatories within 120 days of approval of the Agreement, a plan detailing steps it intends to take to maintain and improve its financial ratings with the credit rating agencies." Section 13.2(g) similarly requires APS to "submit a plan to the Commission to maintain investment grade financial ratios and to improve [the Company's] financial metrics." In fulfillment of these provisions, APS has prepared and hereby submits the following Plan.

Credit Ratings Objectives

APS's ultimate credit rating-related objective is to maintain mid-BBB level or better credit ratings that will enable the Company to finance needed investments at reasonable costs and avoid undue exposure to a potential for downgrade to non-investment grade levels. Given the financial commitments and rate case filing restrictions to which APS is bound, and the current macroeconomic environment, APS believes that an improvement to its current credit ratings is likely to take several years of sustained performance.[1] APS will work to improve its financial metrics and the qualitative factors within its control (which, as discussed below, are important elements within the ratings process), both of which could improve credit quality and better position the Company to achieve its ratings objectives.

[1] Moody's, for example, has indicated that "APS's rating is not likely to be revised upward in the near-to-medium term. Longer term, an upgrade could be possible if there is an increase in supportive regulatory treatment resulting in material, timely rate increases, or if there are material reductions in costs or leverage such that Moody's could anticipate key financial ratios improving significantly from their current levels." Moody's Investors Service, Credit Opinion: Arizona Public Service Company (February 25, 2009).

The Agreement contains several provisions that APS intends to use as vehicles to facilitate eventual promotion to higher credit ratings. Of course, the rating agencies are independent arbiters of credit ratings and APS cannot control their analysis of all the underlying factors. For at least the period between now and December 31, 2014 (the "Settlement Term"), APS's objective is to maintain its current credit ratings at stable levels, improve the underlying financial metrics supporting those ratings, and build on the foundation to improved credit ratings paved by the Agreement.

Ratings Process

Credit rating agencies describe the ratings process as an art as much as a science. This process includes a quantitative assessment of a utility's key financial metrics and other factors, as well as a qualitative assessment of the utility's business position, including its regulatory environment. The evaluation of various key financial metrics such as Funds from Operations ("FFO") interest coverage, FFO/Debt, and Debt/Total Capital is a cornerstone of the quantitative aspect of the rating agencies' credit assessment. However, other factors such as accounting and financial governance policies and practices, cash flow adequacy, liquidity availability and access to capital are also critical quantitative factors.

Just as important as the *quantitative* analysis, however, is a *qualitative* assessment of various criteria that are core to credit quality and directly impact the predictability and sustainability of financial performance. Within the utility industry, these core areas include regulation and the utility's regulatory environment, markets, diversification, operations and management. Although specific ratings assessment approaches and relative weightings of credit factors may differ among the ratings agencies (along with the transparency of the analytical approaches), the concept, context and product are the same – rating

agencies undertake an analysis of key quantitative and qualitative factors driving credit quality and from this analysis they develop and assign ratings to an issuer.

Settlement Term Action Plan

To address the key quantitative and qualitative factors of this evaluation, APS intends to focus primarily on three objectives that address its ratings challenges.

First, the Company expects to earn a Return on Equity ("ROE") around 9% between now and the Company's next rate case, and work to earn closer to its authorized 11% ROE thereafter. Actually earning a ROE at these levels should provide APS with sufficient cash flow to result in a FFO/Debt ratio that supports the Company's present credit ratings. In addition to supporting FFO/Debt, improving the Company's ROE also encourages equity investment, which is necessary to finance capital projects and maintain a balanced capital structure, and is also critical given APS's equity funding commitments. Although rates charged and revenues received from customers are critical factors in earning a reasonable ROE, that metric can also be strengthened by reducing expenses. APS's Plan combines both to achieve its ROE objective.

Second, APS will manage its FFO/Debt ratio and capital structure to comply with the terms of Sections 8.2 and 8.3 of the Agreement, which require the Company to "use its best efforts to maintain investment grade financial ratios and a balanced capital structure that optimizes benefits to ratepayers" and "to strive to achieve a capital structure with no more than 52% debt/total capital, as calculated by the credit rating agencies, by December 12, 2012." Pinnacle West's recent equity issuance of $253 million (described in further detail herein) is an early step in this direction. The strategy to accomplish this objective also includes addressing negative effects of imputed debt.

Third, APS will continue to highlight to credit rating agencies the positive developments in Arizona's regulatory environment, which is the qualitative consideration that S&P deems to be "the most important factor in [its] analysis of a U.S. regulated, investor-owned utility's business risk."[2] In particular, APS intends to build on the momentum gained by the settlement and work with Commission Staff and interested parties on the process improvements discussed in the Agreement that credit rating agencies will view as additional enhancements to Arizona regulation.

To achieve these objectives, APS intends to:

1. **Maintain a Balanced Capital Structure and Infuse Equity as Appropriate.**

APS's capital programs and investment must be financed with an appropriate balance of debt and equity, and both are needed to maintain and strengthen APS's capital structure. APS cannot rely solely on debt to finance its significant capital spending program without damage to its financial metrics, but neither can or should it rely too heavily on equity capital, which is more expensive than debt and increases the Company's overall cost of capital and thus cost to customers.

For these reasons, the Agreement authorized Pinnacle West to infuse $700 million of equity into APS through December 31, 2014, and APS agreed to complete infusions of at least that amount by that date. *See* Agreement at § 8.1. APS completed the first tranche of this commitment through Pinnacle West's issuance of 6,900,000 shares of common stock in April 2010, which resulted in net proceeds to Pinnacle West of approximately $253 million. APS anticipates using these capital contributions to repay short-term indebtedness, to finance capital expenditures, and for other general corporate purposes. As a general matter, and subject to market conditions, the Company expects to issue or obtain new debt and

[2] *See "Assessing U.S. Utility Regulatory Environments,"* Global Credit Portal, Ratings Direct (March 11, 2010).

equity financing as needed to fund its requirements while maintaining a balanced capital structure throughout the Settlement Term.

2. Mitigate Negative Impacts of Credit Rating Agency Debt Imputation.

When calculating a company's debt levels and interest obligations for credit ratings purposes, credit rating agencies impute as debt certain obligations under long-term Purchased Power Agreements ("PPAs"), operating leases, or other contractual arrangements. Because of this practice, any utility that procures resources through PPAs or is a party to long-term operating lease agreements will be deemed effectively to have more debt on its balance sheet than it would without such contracts. Of particular concern is the level of subjectivity, variables, and assumptions at play in the rating agencies' calculation of the debt imputation amounts. These values are less certain and identifiable than balance sheet amounts representative of a debt and equity finance mix. APS, which has a significant portfolio of both renewable and conventional PPAs, is particularly vulnerable to the impact of debt imputation.

Critical to managing and mitigating that impact is investment in utility-owned resources, financed with an appropriate mix of debt and equity – the very type of investment recently approved for APS with AZ Sun for utility-scale renewable generation. The Agreement not only gives APS the key tools needed to make those investments, but requires APS to use those tools to reduce its imputed debt levels. Under Section 15 of the Agreement, APS must acquire significant amounts of renewable energy, such that renewable resources will be approximately 10% of APS's retail sales by 2015. This obligation requires significant financial commitments that – if procured solely through PPAs – could harm the Company's financial metrics and run contrary to APS's commitment to "strive to maintain a 52% debt/total capital ratio as calculated by the credit rating

agencies by December 31, 2012," which the Agreement also requires. *See* Agreement at § 8.3.

A similar option that APS may pursue is to purchase already constructed generation resources to replace PPA resources, assuming favorable pricing. Purchasing such resources, financed with an appropriate mix of debt and equity, would also eliminate the imputed debt impact associated with a PPA. Any such acquisition of a non-renewable generation plant could require a waiver by the Commission from the restrictions of APS's self-build moratorium, in effect until January 1, 2015.

Finally, APS is evaluating its leasehold interests, looking at several viable alternatives that will further mitigate negative impacts of imputed debt on the Company's balance sheet.

3. **Focus on Cost Management.**

An important component of maintaining a reasonable earned ROE between rate cases is disciplined cost management – having processes in place engineered to set budget and cost projections at appropriate levels and keep actual costs within those projected ranges. Maintaining an earned ROE closer to the authorized return, through a combination of the rate relief provided by the Commission and cost management, will support APS's financial metrics. During the Settlement Term, a cost management focus also is critical for APS to meet the Agreement's expense reduction requirement (whereby APS committed to reduce expenses by an average $30 million per year, for a total reduction of $150 million for the Settlement Term, *see* Section 7.1). Consistent with Section 7.3 of Agreement, APS will submit an annual report detailing the specific reductions made each year to meet the Agreement's expense reduction requirements. Pursuant to the Agreement, the first such report will be filed on April 29, 2011.

Some current examples of APS's cost management efforts include:

- APS held its operating budget for 2010 flat compared to 2009 budgeted levels, notwithstanding cost increases for materials and supplies, technology cost increases, maintenance cost increases, and increased maintenance levels required to maintain aging equipment. Doing so required virtually every area of the Company to reprioritize, rebalance, and reassess risk so that APS could hold flat its anticipated spend without jeopardizing the safety of employees or the reliability of service to customers. The same intense focus on cost management was also an important piece of our capital expenditure plan review for 2010.
- APS is restructuring its supply chain organization, transforming the processes by which goods and services are procured to become more efficient and cost-effective. This undertaking is significant. Supply chain management is one of the most important strategic aspects of any capital intensive business. Decisions must be made about how to coordinate the production of goods and services, how and where to store inventory, from whom to buy materials and under what terms, and how to distribute those materials in the most cost-effective, timely manner. Among other things, the supply chain initiative now underway will significantly reduce procurement costs by standardizing the Company's procurement practices and allowing APS to be more strategic about the payment and other contract terms used with vendors, thus obtaining the best value for the Company and its customers.
- APS has adopted and is now implementing a new operations model for its fossil plants that incorporates all aspects of how the Fossil Generation business unit operates. A critical component of the model is a movement to a one-fleet mindset, looking at all of the

Company's plants as one generation fleet that operates consistently and towards common goals. Fossil Generation is also making changes to implement best utility practices with respect to both staffing and processes. The model will drive the fleet towards improved consistency, economies of scale, implementation of best practices, resource and knowledge sharing, and cost management opportunities.

- APS is also implementing a power plant operations strategy to reduce environmental compliance cost exposure in the long-term and certain operational and maintenance ("O&M") expenses in the short run. For example, the Company is looking at various options to address the environmental matters at the Four Corners Power Plant and resolve ownership issues at Units 4 and 5 that may arise given Southern California Edison's indication that California legislation may prohibit it from investing any significant amount in those units going forward. While several complicating variables have yet to be resolved, APS hopes to achieve a result that, with the Commission's approval, will reduce APS's cost exposure under increasingly stringent federal EPA requirements and maintain an important baseload resource to support the Company's increasing acquisition of renewable resources.
- APS has launched an initiative in its Energy Delivery business unit to improve work processes, gain greater consistency in the execution of that work, and enhance the business unit's overall operational efficiency and performance. The Company's use of more modern technology, standardized work methods, and more streamlined processes will enhance its ability to plan, schedule, organize, execute

and monitor the work needed to manage the assets and equipment required to serve customers and reduce costs.

4. Pursue Rate-Related Strategies for Timely Cost Recovery.

As the foregoing describes, APS is focused on analyzing its operations and taking important steps to effectively and efficiently manage costs, finance with the right combination of debt and equity, and mitigate negative ratings impacts of imputed debt. But the sum total of these efforts does not eliminate the Company's need for appropriate rate relief. APS has a significant capital expenditure program devoted, among other things, to building infrastructure needed throughout the state, addressing environmental issues at its generation plants, and otherwise fostering an environmentally-friendly, sustainable, and efficient Arizona energy future. In combination with the other facets of this Plan, adequate and timely cost recovery is critical for APS to improve its ROE and other financial metrics.

In that regard, APS will:

- File a rate case on June 1, 2011, using a 2010 test year as permitted by Section 2.2 of the Agreement. Among other things, this rate filing will present the required information in a format that more transparently aligns the Company's revenue needs and its cost drivers.
- Work with the Settling Parties and Commission Staff to process the case within 12 months of a sufficiency filing, as contemplated by the Agreement. *See* Agreement at § 2.3. The 12 month turnaround provision is important to reducing the negative financial impact of regulatory lag and has been heralded by ratings analysts. APS will facilitate this processing time, both by filing the required 120 day notice of its intent to file, informally discussing issues relating to the rate filing with the parties well before that required notification, and

coordinating the logistics that will enable the parties to meet and confer about the anticipated rate filing, as the Agreement requires. *See* Agreement at § 2.4.

- Actively participate in the Commission's decoupling workshops and pursue a decoupling mechanism that supports the Company's ability to meet the aggressive energy efficiency levels set in the Commission's recent rulemaking without impairing APS's financial performance. S&P recently noted that, properly structured, decoupling "supports creditworthiness because it can lessen volatility in revenues and cash flow." Assurance of recovery of APS's fixed costs through decoupling will send a positive signal to the rating agencies that Arizona's regulatory environment is one that will support the Company's financial health while furthering important policy goals.
- Continue using FERC formula rates to recover costs for additional transmission investments, and pursue timely approval of the Company's Transmission Cost Adjustor applications each year.

5. Support the Capital Markets' Evolving Perception of Arizona's Regulatory Environment and Other Qualitative Factors.

Ratings agencies appropriately recognized the Agreement as a major milestone demarking what they believe to be an increasingly supportive regulatory environment. All three ratings agencies have described the Commission's approval of the Agreement as an indication of improving credit quality. S&P noted that "recent rate activity is evidence that the company's management of regulatory risk has improved" and that "interim rates and recovery of certain post-test year costs

have mitigated some risk in APS's latest case."[3] Moody's similarly affirmed APS's current rating after the Agreement was approved to reflect its view of APS's "continued financial and operating performance as well as recent decisions and recommendations of the Arizona Corporation Commission (ACC) and the ACC Staff respectively, which in our opinion appear to be somewhat more supportive than had historically been the case . . . . We believe the potential for rate settlements has increased, which could also potentially reduce regulatory lag."[4] Fitch also described the Agreement's approval as "supportive of APS's current credit ratings and a constructive development for APS fixed income investors."[5]

As a means of further improving this key qualitative aspect of the utility credit quality, APS plans to work with the Commission and other parties to capitalize on the momentum gained during the settlement. To that end, APS intends to:

- Pursue ratemaking mechanisms and processes that will allow APS to implement important state and federal policy objectives and move Arizona further into the evolving energy future without degradation to the Company's financial metrics;
- Work with the Commission and other interested parties to reach constructive agreements to settle future cases, if practicable, in order to conserve Commission resources and mutually promote shared goals.

Although credit ratings agencies deem "regulatory environment" to be the most important qualitative factor governing their assessment of investor-owned

---

[3] Standard & Poor's, RatingsDirect, Arizona Public Service Company at 2 (December 22, 2009).

[4] Moody's Investors Service, Rating Action: Arizona Public Service Company (February 23, 2009).

[5] Fitch Ratings, Corporates, Global Power U.S. & Canada Credit Update: Arizona Public Service Company (December 30, 2009).

utility risk profiles, others are also considered, including market position, operational performance, and company management (looking at such things as a commitment to credit quality, operating efficiency and cost control). Many of the steps outlined in this Plan address these other qualitative considerations, as to which APS will continue to advocate its strong performance.

Conclusion

The Agreement was an important step in the right direction towards stabilizing the Company's credit quality. Going forward, the Company will focus on maintaining a balanced capital structure and issuing equity and debt as appropriate; managing costs; and implementing strategies that mitigate negative impacts of imputed debt. Capitalizing on and furthering the momentum achieved during the settlement, APS also will work with the Commission and stakeholders as it pursues a decoupling mechanism and other forms of rate relief that are both timely and adequate to give APS a reasonable opportunity to earn its authorized rate of return. Collectively, these and other future efforts should improve APS's financial health and credit quality.

ARIZONA PUBLIC SERVICE COMPANY
PROJECTED INCOME STATEMENTS
WITH PROPOSED RATE INCREASE EFFECTIVE JULY 1, 2012
(Thousands of Dollars)

Line No.	Description	Projected Year - Total Company			Projected Year - ACC Jurisdiction			Line No.
		Year Ended 12/31/2011 (A)	Year Ended 12/31/2012 (B)	Year Ended 12/31/2013 (C)	Year Ended 12/31/2011 (D)	Year Ended 12/31/2012 (E)	Year Ended 12/31/2013 (F)	
1.	Electric operating revenues	$ 3,242,469	$ 3,478,076	$ 3,693,927	$ 3,105,016	$ 3,366,243	$ 3,597,375	1.
2.	Fuel and purchased power	985,439	1,042,104	1,066,762	1,114,392	1,205,740	1,266,823	2.
3.	Operating revenues less fuel and purchased power	2,257,030	2,435,972	2,627,165	1,990,624	2,160,503	2,330,552	3.
	Other Operating Expenses:							
4.	Operations and maintenance excluding fuel and purchased power *	963,110	1,017,251	1,088,409	864,047	940,064	1,008,530	4.
5.	Depreciations and Amortization	421,726	404,136	440,345	373,804	350,955	380,136	5.
6.	Income taxes	192,641	253,878	273,496	176,711	222,980	240,683	6.
7.	Other taxes	153,869	174,953	194,124	130,732	148,610	164,894	7.
8.	Operating income	525,684	585,754	630,791	445,330	497,894	536,309	8.
	Other Income (Deductions):							
9.	Income taxes	4,410	8,272	11,385	107	429	894	9.
10.	Allowance for equity funds used during construction	26,691	24,490	23,276	22,447	20,840	17,923	10.
11.	Other income	5,036	2,094	1,367	(270)	(1,086)	(2,263)	11.
12.	Other expenses	(15,664)	(16,973)	(19,693)	-	-	-	12.
13.	Total	20,473	17,883	16,335	22,284	20,183	16,554	13.
14.	Income Before Interest Deductions	546,157	603,637	647,126	467,614	518,077	552,863	14.
	Interest Deductions							
15.	Interest on long-term debt	214,337	209,732	226,870	172,349	167,471	178,369	15.
16.	Interest on short-term borrowings	6,007	8,593	7,815	4,827	6,856	6,140	16.
17.	Debt discount, premium and expense	4,584	3,655	3,788	3,683	2,916	2,976	17.
18.	Allowance for borrowed funds used during construction	(17,437)	(22,746)	(23,322)	(14,650)	(19,015)	(17,256)	18.
19.	Total	$ 207,491	$ 199,234	$ 215,151	$ 166,209	$ 158,228	$ 170,229	19.
20.	Net Income	$ 338,666	$ 404,403	$ 431,975	$ 301,405	$ 359,849	$ 382,634	20.
21.	Return on Year End Common Equity	8.6%	9.3%	9.5%	9.6%	10.4%	10.8%	21.
22.	Return on Average Common Equity	8.8%	10.0%	9.7%	9.7%	10.9%	11.0%	22.

Notes:
* Includes expenses related to Renewable Energy Standard and Demand Side Management programs.

Mark A. Schiavoni

TESTIMONY OF MARK A. SCHIAVONI

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-_____

June 1, 2011

Table of Contents

I. INTRODUCTION 1

II. SUMMARY 2

III. INTRODUCTION TO FOSSIL GENERATION 2

A. Overview of Fossil Generation 2

B. Focus on Safety 8

C. Focus on reliability 13

D. Focus on the Environment 18

E. Focus on Cost Management 24

IV. TOTAL FOSSIL GENERATION OPERATIONS AND CAPITAL REQUIREMENTS 26

A. Total Capital Expenditures at the Fossil Plants. 26

V. BENCHMARK STUDY RESULTS FOR THE FOSSIL PLANTS 27

VI. CONCLUSION 28

Fossil Generation Post-Test Year Plant Additions ..... Attachment MAS-1

TESTIMONY OF MARK A. SCHIAVONI
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-_____)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Mark A. Schiavoni. I am the Senior Vice President of Fossil Generation at Arizona Public Service Company ("APS" or "Company"). In that capacity, I am responsible for overseeing all facets of the Company's non-nuclear generation plants, including operations of over 6,600 megawatts of fossil and renewable energy. This includes outage and work management, plant engineering and technical support, and operational oversight of co-owned facilities.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I joined APS in 2009 from Exelon Corporation ("Exelon"), where I spent nine years, most recently as Senior Vice President of Exelon Generation and President of Exelon Power. I began work at Exelon in 2000 as a nuclear plant manager, after which time I assumed various senior executive positions overseeing Exelon's fossil, hydroelectric and renewable facilities, as well as the construction and integration of new generation assets. Before joining Exelon, I worked as a nuclear plant maintenance director for both Florida Power and Centerior Energy Corporation. Prior to that, I spent 22 years in the U.S. Navy's nuclear program.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I spoke at the Commission's November 18, 2010 Special Open Meeting on the topic of how an Environmental Protection Agency ("EPA") proposed rule impacts Four Corners power plant ("Four Corners"). I have also filed written testimony supporting APS's application to acquire SCE's portion of Four Corners Units 4-5 in Docket No. E-01345A-10-0474.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony provides a general overview of APS's Fossil Generation business unit, and provides a high level picture of what is required to safely and reliably generate electricity at the Company's fossil plants. Specifically, I examine Fossil Generation's intense focus on safety, reliability, the environment, and cost management. I also identify the specific projects completed in the 2010 Test Year and through June 30, 2012, and isolate Fossil Generation's contribution to the Company's post-Test Year Plant Adjustment. Finally, I address certain recommendations made by Liberty Consulting Group ("Liberty") in its Benchmarking Study of APS.

III. INTRODUCTION TO FOSSIL GENERATION

A. *Overview of Fossil Generation*

Q. TO WHAT DOES "FOSSIL GENERATION" REFER?

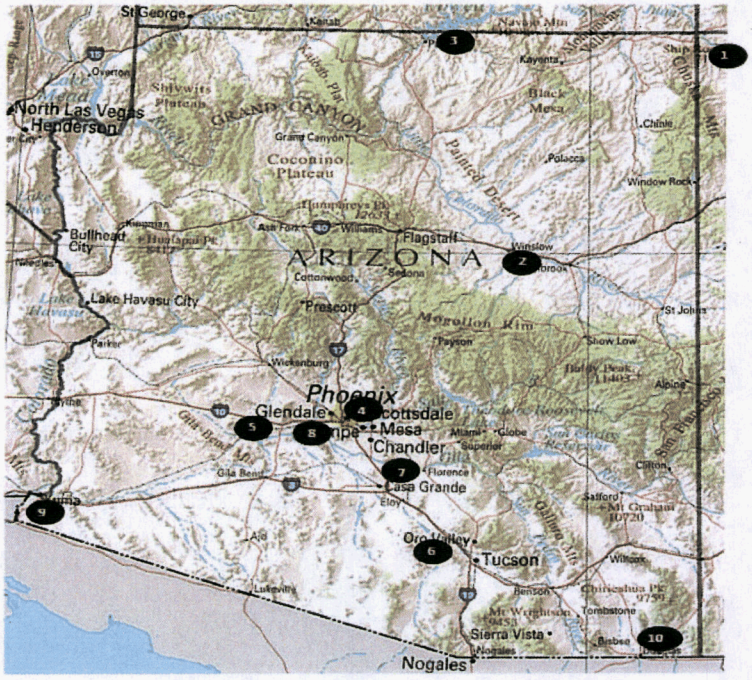
Fossil Generation is an APS business unit that operates a fleet of two coal-fired, six natural gas-fired, and one oil-fired generating station, which collectively provide over 6,600 megawatts of reliable capacity. APS also owns 14% of the Navajo Generating Station, operated by Salt River Project ("SRP"). In total, over 5,100 megawatts of the capacity generated by our fleet serve APS customers – meeting approximately two-thirds of our customers energy needs. Fossil Generation is also constructing several new utility-scale solar photovoltaic generation facilities that will join our generation fleet. At present, Fossil Generation has a workforce of about 960 employees. Our 2010 work plan required capital expenditures of $112.8 million and an operations and maintenance ("O&M") budget of $190.2 million.

Collectively, the APS plants within the Fossil Generation fleet have baseload, intermediate, and peaking capabilities that complement the power produced by

Palo Verde Nuclear Generating Station. The coal plants, with low fuel costs, provide base load power and have averaged capacity factors in the range of 80-85% over the past decade. APS's gas plants – and, soon, its solar facilities – serve as our intermediate and peaking resources.

Q. PLEASE BRIEFLY DESCRIBE APS'S FOSSIL GENERATION FLEET.

A. As the following map and corresponding table demonstrate, nine of the ten power plants within the APS Fossil Generation fleet are scattered throughout Arizona. Four Corners, the first plant listed below, is located in Farmington, New Mexico.



Summary Table of Generating Capabilities

	PLANT	FUEL TYPE	UNITS	OWNED CAPACITY
❶	Four Corners	Coal	5	791
❷	Cholla	Coal	3	647
❸	Navajo	Coal	3	315
❹	Ocotillo	Natural Gas	4	330
❺	Redhawk	Natural Gas	2	984
❻	Saguaro	Natural Gas	5	399
❼	Sundance	Natural Gas	10	420
❽	West Phoenix	Natural Gas	7	997
❾	Yucca	Natural Gas	6	243
❿	Douglas	Oil	1	16
	Total Fleet		46	5,142

Allow me to elaborate a bit more on each of these plants:

- *Cholla:* The Cholla power plant ("Cholla") is a four-unit coal-fired plant located near Holbrook, Arizona. APS operates the plant and owns Units 1, 2 and 3, with a combined capacity of 647 megawatts. PacifiCorp owns Unit 4, with a 380 megawatt capacity. In addition, because APS and PacifiCorp have opposite periods of seasonal demand, we benefit from a seasonal power exchange agreement pursuant to which PacifiCorp receives electricity from the APS system during the winter when electricity demands are high in the Northwest, and APS receives an equivalent amount of power from PacifiCorp during the summer, our period of peak demand.

- *Four Corners:* The Four Corners power plant is a five-unit, 2,100 megawatt coal-fired plant located on the Navajo Nation, 24 miles west of Farmington, New Mexico. At present, APS owns Units 1, 2 and 3 and shares ownership of Units 4 and 5 with five other utilities. The units are

fueled by low-sulfur coal from the nearby Navajo mine (operated by BHP Billiton ("BHP")). As BHP mines the coal, it is transported to a reclamation pile by electric railroad. A conveyor belt system delivers coal from the reclamation piles to the unit's coal bunkers. Water is supplied by the San Juan River to Morgan Lake, located near the plant and containing over 1,200 surface acres of water. APS's current share of the plant's total production is 791 megawatts. APS has contracted to purchase an additional share of Units 4 and 5 from Southern California Edison, which acquisition is the subject of another docket.[1]

- *Navajo:* The Navajo power plant ("Navajo"), a three unit coal-fired facility operated by SRP, is located in northern Arizona on the Navajo Indian Reservation near Page. It has a total production capacity of 2,250 megawatts. The plant is jointly-owned with four other utilities and the U.S. Bureau of Reclamation, and APS has a 14% interest in the plant. The plant is fueled by low-sulfur coal from the nearby Peabody Kayenta Mine at Black Mesa. An electric railroad delivers coal to the plant from the mine, which is located on the Navajo and Hopi Indian Reservations.

- *Douglas:* APS's Douglas power plant (sometimes referred to as "Fairview"), is located in the town of Douglas in Southeastern Arizona. It is comprised of one 16-megawatt diesel-fueled combustion turbine ("CT") peaking unit installed in 1972, which normally operates only in emergencies. The plant has no full-time employees, but is operated and serviced by employees from APS's Sundance plant, near Casa Grande.

[1] *See* Docket No. E-01345A-10-0474.

- *Ocotillo:* APS owns and operates the Ocotillo natural gas power plant ("Ocotillo") located in Tempe, near Phoenix's center of customer demand and thus strategically important to summer reliability. The plant, served by the El Paso Natural Gas pipeline, has two steam-units and two CT units. The site has a total generating capacity of 330 megawatts.

- *Redhawk:* APS owns and operates the Redhawk power station ("Redhawk"), a natural gas plant comprised of two identical 492-megawatt combined-cycle units. Both the El Paso Natural Gas and Transwestern pipelines supply the facility. The plant is located 50 miles west of Phoenix. Because the facility is located in the desert without access to a reliable supply of surface water, the plant uses treated effluent purchased from Palo Verde to meet its cooling needs. To minimize cooling water use, Redhawk was designed as a zero liquid discharge site. In other words, the cooling process continually reclaims and reuses cooling water — no water is released into the environment.

- *Saguaro:* The natural gas-fueled Saguaro power plant, located north of Tucson, has two steam units and three combustion turbine units. The plant is served by the El Paso Natural Gas pipeline. APS owns and operates all five units, which have a combined capacity of about 399 megawatts. The site is managed by the Sundance leadership team.

- *Sundance:* The simple-cycle, natural gas-fueled Sundance Generating Station, located near Casa Grande, consists of 10 quick-start CT units that have a combined production capacity of 420 megawatts. The plant is served by both the El Paso and Transwestern pipelines, providing options for fuel delivery.

- *West Phoenix:* Located in Southwest Phoenix, the natural gas-fueled West Phoenix power plant has seven generating units, consisting of two CT units and five combined-cycle units. Like Ocotillo, West Phoenix is located near Phoenix's center of customer demand and is strategically important to summer reliability. The plant is served by El Paso Natural Gàs pipeline. Operated and owned by APS, West Phoenix is capable of generating about 1,000 megawatts of electricity. Like Redhawk, West Phoenix uses zero liquid discharge technology for the Combined Cycle Units 4&5 for cooling to focus on water economy.

- *Yucca*: APS operates the natural gas-fueled Yucca Power Plant near Yuma. Yucca consists of six CT units that produce nearly 243 megawatts for APS customers, as well as a 75 megawatt steam unit and a 22 megawatt CT unit, both of which are owned by the Imperial Irrigation District ("IID"). Yucca CTs 1, 2 & 3 and the IID steam plant are served by the El Paso pipeline. In March of 2010, Yucca CTs 5&6 were connected to the North Baja natural gas pipeline. In March 2011, the IID steam unit was also connected to the North Baja pipeline. CT 4 and the IID CT both run on oil only, because historically there was insufficient gas transport for these units.

Q. WHAT IS THE MISSION OF FOSSIL GENERATION?

A. Fossil Generation's mission, simply put, is to be the best. We will deliver superior operational performance while instilling a strong safety culture and protecting our environment. Getting there is no easy task. Fossil Generation faces a variety of challenges, including an aging workforce and plants, preparing for and complying with continually-evolving environmental regulations and

policy developments that require significant cost investments, and operating in step with APS's aggressive corporate-wide focus on cost management.

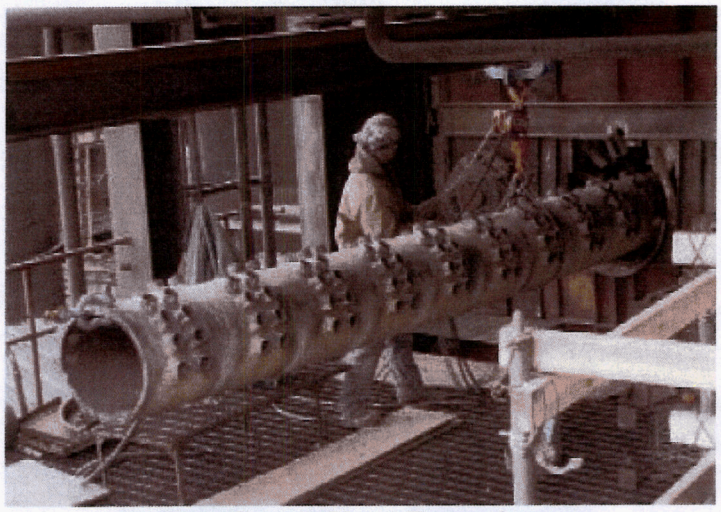
B. *Focus on Safety*

Q. WHAT IS FOSSIL GENERATION DOING TO INSTILL A STRONG SAFETY CULTURE, AND AT WHAT COST?

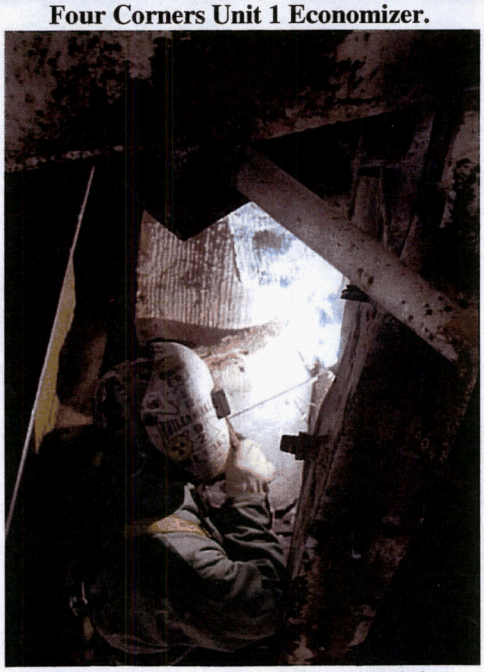
A. Safety is a core value at APS, and a key part of Fossil Generation's operating mission. Running a power plant is inherently hazardous, and the men and women who work at our plants generating power for customers throughout the Southwest face significant safety risks each and every day. Think of how a steam unit generates electricity: a fuel is burned in a huge boiler to create enough heat to turn water into steam. That steam is highly pressurized and carried through thick metal pipes to the turbine. The turbine rapidly spins a generator, which changes mechanical spinning energy into electricity. The following illustrate the types of machinery involved in the process:

Four Corners Unit 5 Low Pressure Rotor/Turbine.

Four Corners Transformer.



Four Corners Unit 1 Economizer.



Typical Boilermaker/Welder Activity.

Combustion Turbine Load Tunnel Inspection.

This operation is replete with safety hazards. Power plant workers work with hazardous materials, high temperature and pressure piping, and rotating equipment every day. The innately dangerous working conditions at power plants require APS to make safety its first priority and insist that our employees and contractors do the same. That is the message behind the Company's "Got Safety – Get Zero!" campaign, and a critical focus for Fossil Generation. Safety is our #1 priority. I have often told the Fossil employees that there is no task so urgent that safety should be compromised.

Fossil's business plan for 2011 outlines a detailed approach to emphasize safety with our employees so as to eliminate "at risk" behavior (inappropriate actions on the part of our workers that increase risk) and achieve zero injuries. To reach this goal, Fossil Generation has designed a comprehensive safety management system to protect plant workers, visitors, and the public from safety hazards. As part of this program, we have developed, among other things, a standard set of safety protocol and training presentations, a procedure for conducting personal safety accountability meetings, and a safety assessment protocol. Our safety policies require all employees to regularly undergo standardized safety training, all

managers to start daily meetings with safety messages, all plants and equipment to undergo safety inspections and audits, and a quarterly fleet-wide "safety stand-down," in which every worker in every unit of APS's Fossil Generation fleet devotes a half-day to focus as a fleet on a variety of safety and related topics.

Most safety issues can and should be avoided if power plant workers are diligent about assessing how their behavior and attitudes contribute to safety incidents and other events (what we call "Human Performance"). For that reason, I repeatedly emphasize the need for our employees to keep cautious and vigilant so as to predict, manage and prevent error-likely situations; rely on organizational processes and values as a means of influencing individual behavior; understand the reasons that mistakes occur; and apply the lessons learned from past events to avoid similar incidents in the future. We aim to achieve these fundamental behaviors through encouragement and reinforcement, from the highest ranking positions in the business unit down.

For example, Fossil Generation implemented the Station Event Free Clock process in the fourth quarter of 2009 to encourage close attention to Human Performance. Each generating station installed a clock to measure the time passed since the last Human Performance-related incident. Each plant's progress in this regard is tracked on our internal website, and recognition is given to plants with positive results. In 2011, we will implement a similar "Event-Free Clock" process on a departmental level. Acknowledging and discussing the precursor events to safety incidents gives front-line supervisors and department managers opportunities to learn from events and ensure that employees understand their performance expectations. My team and I are working hard to make Fossil Generation a self critical and continuous learning organization. This, we believe, will drive sustainable and safe plant performance.

Q. WHAT ELSE DOES FOSSIL GENERATION DO TO PROMOTE A SAFE WORKING ENVIRONMENT?

A. Fossil Generation provides standardized personal protective equipment for all of its employees and others working at the plant, including safety shoes, protective eyewear, hearing protection, and hard hats. We also supply a variety of other equipment to protect employees from hazards associated with specific job assignments. This includes "spoggle" eyewear for areas of high wind and dust, hand protection for all types of tasks, and fire resistant and arc flash rated clothing. Our plants have also upgraded their safety equipment to include devices used to automatically open and close a circuit breaker from a remote location, thereby removing operations personnel from manual contact with the circuit breaker increasing personal protection from arc flash hazards; safety swing gates that automatically close on industrial ladders, protecting our workers from falls; and additional welding outlets to reduce the number of tripping hazards associated with welding equipment.

From a cost perspective, these and other safety-related measures required expenditures of more than $5.5 million in 2010, a number that will increase for 2011 and 2012. This figure does not include the cost of maintenance, described below, which is also important for safety. This is money very well spent. Indeed, we have already seen a marked improvement in our safety metrics: where Fossil Generation employees experienced 27 OSHA recordable injuries in 2009 (including one fatality), we had only 10 last year (and no fatalities) – an almost two-thirds reduction.

C. *Focus on reliability*

Q. IS THE FOSSIL GENERATION FLEET RELIABLE?

A. Yes, and it is becoming more so each day. As the Benchmarking Report published by Liberty Consulting Group found, when measured by capacity factor, "the performance of the APS units is at the top of the industry," "generally in the first quartile in their panels."[2] Our fossil plants overall also demonstrate above-average performance in terms of availability (measured by the "Equivalent Availability Factor").[3] Although some units have historically performed better than others, particularly with respect to forced outage rates, Fossil Generation is putting the mechanisms in place to drive improved reliability performance where opportunities exist to do so. Indeed, recent benchmarking studies indicate that current performance metrics trend in the right direction – a reflection of changes to our operations model.

Q. PLEASE DESCRIBE GENERALLY WHAT FOSSIL GENERATION DOES TO MAINTAIN ITS FLEET TO BE SAFE AND RELIABLE.

A. Keeping our fleet operating safely and reliably requires significant time and money. Imagine all of the various machines at work inside of a fossil power plant (boilers, generators, turbines, etc.), and all of the many components that make up those machines (metal pipes, coils, tubes, wires, and shafts, to name a few), with an average age of 42 years for our coal plants and 25 years for our Gas & Oil plants. Each of these components in all of the 46 units in our fleet must be inspected and maintained consistently if our plants are to provide safe and reliable power for our customers. Although Fossil Generation has always had policies in place towards that end, we have recently increased our rigor and focus on plant maintenance. The comprehensive set of standardized policies and procedures to which we adhere are designed to ensure that the fleet is working to

[2] *See* Liberty Benchmarking Report at 12.

[3] *See* Liberty Benchmarking Report at 12; Concentric report, attached to the Testimony of Jeff Guldner.

achieve continually improving reliability, measured not just by capacity factor but by ensuring the power is there when our customers need it.

Pursuant to these policies, our plants undergo regular preventative, predictive, and corrective maintenance, as well as planned overhaul outages. Fossil Generation's preventative maintenance program, for example, requires that specific routine maintenance work be done at each of the units at specified periods. As one would change the oil in his or her car on a regular basis, so do we maintain our generation equipment at regularly prescribed intervals. When conducting predictive maintenance, we carefully monitor a given piece of equipment and perform needed upkeep when conditions require (for example, when a component's temperature approaches an unacceptable range) rather than doing so on an arbitrarily set date. Predictive maintenance generally makes sense over preventative maintenance when the maintenance cost for a component is high, thus justifying more comprehensive monitoring. No matter how good our preventative and predictive maintenance programs are, parts can and do break. When they do, we perform "corrective maintenance" to fix them.

In addition, each of the units in the Fossil Generation fleet undergoes regular inspections that vary in depth and scope to identify equipment problems that may impact plant safety or reliability (such as corroded metal or stress on high pressure piping). Routine inspections assess how the machinery is performing without physically examining the inside of the equipment. At our coal plants, a more comprehensive analysis, "minor overhaul," is generally done every 3 years (or other period as dictated by the nature of the plant) and an even more comprehensive "major overhaul" is conducted every 6 years (or as otherwise appropriate). For our gas and oil fleet, minor overhauls are generally conducted every 3 to 4 years, and major overhauls occur every 8 to 9 years. These more

extensive analyses take place during planned plant outages, allowing our engineers and mechanics to actually get inside of the machines to physically examine them and better identify any potential problem areas. We also take advantage of these planned outages to repair or replace any components that are showing signs of stress.

Of course, all of our maintenance and inspection work must be carefully managed and monitored to ensure its completion. To that end, Fossil Generation is putting in place a comprehensive work management system that tracks all of the work that must be done on each of the units throughout the fleet and generates the work orders and manual tasks that our plant employees do daily.

Q. DOES APS FACE ANY PARTICULAR ISSUES THAT MAKE ITS FLEET MORE COSTLY TO MAINTAIN?

A. Yes. Six of the nine coal units in Fossil Generation's operated fleet are over 40 years old and require higher levels of capital investment to maintain relative to the newer units. Like a car or any other piece of equipment, the older the unit, the more likely the wear and degradation of its parts as well as obsolescence. Older facilities thus tend to need more maintenance and require more frequent component upgrades compared to newer ones. As I will describe in detail, that cost is compounded by the costs needed to install and operate emissions control equipment so as to meet environmental regulations. Issues with coal quality also impact plant operation and costs at the Four Corners Generating Station, as I later describe.

Q. WHAT COST IS REQUIRED TO ENSURE RELIABLE PERFORMANCE OF THE FOSSIL GENERATION FLEET?

A. The inspections and other activities described above require significant capital and O&M dollars. APS's share of the fleet's total reliability-related spend in the

2010 Test Year exceeded $175 million. These expenditures include the following:

- A major overhaul of the combustion and steam turbines at Unit 1 of APS's Redhawk's natural gas plant, the first such overhaul since Redhawk went into commercial service in 2002. This project required workers to disassemble, clean, inspect and replace/repair each of the components of these turbines to promote their continued reliability. The overhaul took 53 days to complete and cost over $40 million ($12 million in O&M costs and $28.7 million in capital).

- Replacement of the cooling towers motor control center and related parts at Units 1 and 2 of the Ocotillo natural gas plant. All thermal power plants produce waste heat energy as a byproduct of the useful electrical energy produced. Cooling towers remove the heat from the process water to improve power plant efficiency. As its name suggests, the cooling tower motor control center is a device that contains the switches and mechanisms that control the operation of the cooling tower motors. Replacing this device for Unit 1 and Unit 2 was necessary as a result of aging allowed for the continued operation of the cooling tower and cost $1.5 million.

  Replacement of various portions of the boiler in Unit 2 of Cholla power plant, so as to reduce the possibility of a boiler tube leak. Were the boiler tube to leak, steam would escape into the boiler and would not be released into the turbine – an essential part of electricity generation. Tube leaks can result in a forced outage of three to six days for repairs. The boiler tubing had corroded beyond repair and needed to be replaced. Doing so supported the plant's continued reliability and cost $1.6 million.

Q. PLEASE IDENTIFY THE RELIABILITY-RELATED CAPITAL PROJECTS THAT FOSSIL GENERATION WILL COMPLETE BY JUNE 30, 2012.

A. A listing of all of the capital projects that Fossil Generation will place in service for customers by June 30, 2012 is attached to my testimony at MAS-1. These projects include the following:

- A major overhaul of the combustion and steam turbines at Unit 2 of APS's Redhawk natural gas plant, completed on April 2, 2011. This project is similar to that required for Unit 1 in 2010, requiring workers to disassemble, clean, and inspect each of the components of these turbines to promote their continued reliability. This overhaul took 56 days and required a capital cost of $39.6 million.

- Replacement of the "horizontal superheater" section of the boiler tubing and its support system at Unit 1 of Cholla power plant, so as to prevent equipment failure and reduce the possibility of tube leaks. The original superheater had been in service for more than 30 years and had degraded. This project will support the Unit's reliability, and was completed in April of 2011 at a cost to APS of $4.7 million.

- Replacement of the blades in the low pressure portion of the turbine at Unit 1 of Cholla power plant. The prior blades had suffered stress crack damage and needed to be replaced so that they did not break during operation and cause extensive and costly damage to other parts of the turbine. This reliability-related project was completed on April of 2011 and cost APS $3.1 million to complete.

- Replacement of the evaporative coolers at West Phoenix CC Unit 2 and Unit 3. Combined cycle units generate greater levels of electricity with

cool dense air than they do with hot, thin air. Evaporative coolers are used to cool the inlet air and increase its density during the hot summer time so that the units continue to generate reliable levels of power. The prior evaporative coolers had corroded over time and needed to be replaced. The upgrades were completed in April of 2011 at a cost to APS of $2.4 million.

D. *Focus on the Environment*

Q. IS FOSSIL GENERATION FOCUSED ON PROTECTING THE ENVIRONMENT?

A. Yes. Fossil Generation is committed to continually improving the environmental performance of our fleet – it is an integral part of our stated mission. Not only do we diligently comply with the increasing environmental regulations that apply to fossil plants, we also proactively plan for regulations that we expect will be implemented in the future and continuously look for new ways to minimize our environmental footprint in a manner that is cost-effective for our customers.

Q. PLEASE DESCRIBE THE ENVIRONMENTAL CHALLENGES FACING FOSSIL GENERATION.

A. APS, like other fossil-fueled electric generators, faces several environment-related regulatory pressures from federal, state, and local regulators. These include the federal Environmental Protection Agency ("EPA"), which regulates Four Corners Power Plant; Maricopa County Air Quality Department, which regulates the Maricopa County-based fossil plants (Redhawk, Ocotillo and West Phoenix); Pinal County Air Quality Control District, which regulates the Pinal County plants (including Saguaro and Sundance); and the Arizona Department of Environmental Quality, which regulates the non-Maricopa or Pinal County fossil plants (including Yucca and Cholla). Each agency has its own set of environmental rules and regulations that are at least as stringent as their federal counterparts. In some instances, local environmental regulations are more

stringent than the corresponding federal requirement, due to environmental circumstances unique to the locality.

The rules that these and other regulators promulgate place increasing environmental and cost pressures on our plants and require intense focus and planning to address cost-effectively. Such rules include, among others, an EPA rule that will require the installation of Best Available Retrofit Technology ("BART") at Four Corners and Cholla, a Coal Combustion Residuals ("CCR") rule that will govern ash disposal at Four Corners and Cholla, a rule that would regulate emissions of hazardous air pollutants from Four Corners and Cholla, a rule that would establish emissions performance standards for existing coal-fired power plants, and a Clean Water Act cooling water intake structures rule that would establish national standards applicable to Four Corners.

Q. HOW DOES FOSSIL GENERATION MONITOR ITS COMPLIANCE WITH ENVIRONMENTAL REGULATIONS?

A. While APS has always had mechanisms in place to monitor our fossil plants' compliance with environmental regulations, Fossil Generation increased this focus in 2010 by creating an environmental department specifically within the Fossil Generation business unit. This group is tasked with providing governance and oversight as well as interface with the communities in which we operate and the regulators on all environmental issues that may impact fossil operations. The department owns the detailed policies that govern Fossil Generation's environment-focused operations. Among other things, these policies require regular testing and monitoring of our plant equipment so as to ensure continued compliance with applicable laws and regulations.

To keep up-to-date on pending environmental issues, Fossil Generation's environmental team works regularly with various agencies on an ongoing basis.

We also actively participate in national utility and industry groups focused on air, water, waste, and other environmental issues. Cooperation with other affected utilities allows APS to identify key developments as they arise.

Q. DOES FOSSIL GENERATION PLAN FOR FUTURE ENVIRONMENTAL REGULATIONS? IF SO, HOW?

A. Absolutely. When we foresee that a new regulation may impact some portion of our fleet, Fossil Generation develops working teams that include members from each part of the Company whose perspective is needed to develop an integrated approach to cost-effectively address the issue. Our engineering department examines the options available to meet the potential rule early in rulemaking process so that these alternatives and their costs and schedules are available as we prepare comments to the proposed rule and for business planning purposes. Fossil Generation's environmental department drafts or amends policies and develops training as needed to provide guidance on the new rule and outline the steps required to become and remain compliant.

From a budgeting perspective, Fossil Generation keeps its leaders continuously informed of regulatory developments so that they may account for environmental concerns in the budgeting and operational planning process. When the pending regulation is sufficiently close to finalization, the working team assesses the likely timing for and cost of compliance, and – when appropriate – includes those costs in the Company's long range forecast to be considered in corporate financial projections. When it is cost effective to do so, Fossil Generation completes required environmental upgrades in advance of the rule. For example, APS began early the process of installing ash pond liners to comply with not-yet-final ash handling and management regulations because it made good business and environmental sense to do so.

Fossil Generation is also pursuing ISO 14001:2004 certification for its plants. ISO 14001 is governed by the International Organization for Standardization ("ISO") based in Geneva, Switzerland. The program is an internationally recognized Environmental Management System ("EMS") that helps organizations minimize how their operations negatively affect the environment, comply with applicable laws, regulations, and other environmentally oriented requirements, and continually improve their performance. The certification process ensures the conformance of a company's EMS against the international standard, as well as any organizational specific requirements that have been identified. Fossil Generation's business plan includes having the fleet ISO certified by the end of 2012.

Q. DOES FOSSIL GENERATION DO ANYTHING BEYOND WHAT IS REQUIRED BY LAW TO MINIMIZE THE ENVIRONMENTAL IMPACT OF POWER PRODUCTION?

A. Yes, we do. One of APS's critical areas of focus is environmental stewardship, and Fossil Generation supports that direction by doing what it can to cost-effectively minimize the environmental footprint of our fossil plants. For example, we have drafted a pollution prevention plan not directed toward any specific environmental requirement, have set goals for recycling and waste reduction, review our aging equipment to determine whether upgrades would cost-effectively improve efficiency, track emissions to ensure that our units are trending in the right direction, and evaluate our use and reuse of water resources to prevent waste. More globally, environmental awareness has been and continues to be integrated into all of Fossil Generation's operational processes and procedures so as to minimize the environmental impact of our operations. Fossil Generation's business model emphasizes continuous improvement, and we constantly look for new ways to operate cost-effectively in an environmentally-conscious manner.

Q. WHAT WAS THE COST OF ENVIRONMENTAL COMPLIANCE DURING THE 2010 TEST YEAR?

A. The regulatory compliance-related activities described above require significant capital and O&M dollars. APS's share of the fleet's total environmentally-driven spend during the 2010 Test Year was roughly $46 million. These expenditures include the following key items:

- Ash disposal projects at Four Corners power plant required to meet regulatory and other combustion by-product requirements governing the disposal of coal ash. Fly ash and bottom ash are by-products of the coal combustion process used to supply steam to the Four Corners turbines. These coal combustion by-products must be disposed of in accordance with regulatory requirements. These projects, part of a multi-year effort to achieve regulatory compliance, cost APS in excess of $4.7 million in 2010.

- Implementation of low nitrous oxide ("NOx") burners and separated overfire air systems at Navajo power plant. This pollution control equipment is the technology alternative to a Selective Catalytic Reduction ("SCR") system as a means of reducing NOx emissions to the levels required by the EPA. This project, required by environmental regulation, cost APS $2.2 million in 2010.

- High volumes of chemicals are required to operate the "scrubber systems" installed at the coal-fired power plants. A "scrubber system" is a very large pollution control device that removes the sulfur dioxide ("SO2") naturally produced during the combustion process. SO2, as well as various other pollutants, can be successfully "scrubbed" out of the flue gas stream using a process called lime scrubbing. Lime is a neutralizing agent that

reacts with the acid gasses in the gas stream, producing calcium salts (which can be used in cement manufacturing). In 2010, APS's chemical cost related to the Cholla power plant scrubbers was $5.8 million.

Q. PLEASE IDENTIFY THE ENVIRONMENTALLY-DRIVEN CAPITAL PROJECTS THAT FOSSIL GENERATION WILL COMPLETE BY JUNE 30, 2012.

A. As previously noted, a listing of all of the capital projects that Fossil Generation will place in service for customers by June 30, 2012 is attached to my testimony at MAS-1. These projects include the following:

- Continued ash disposal upgrades at Four Corners power plant, needed to meet EPA requirements governing the disposal of coal ash. These projects are part of the multi-year effort necessary to ensure that ash is disposed of in accordance with environmental regulations. The projects will be completed in the last quarter of 2011 and cost APS in excess of $11.7 million.

- Replacement of the SCR catalyst at Redhawk and West Phoenix natural gas plants. As indicated above, SCR is an emission control technology that uses a catalyst to convert NOx into diatomic nitrogen and water. A catalyst is a material that changes the rate of the chemical reaction; it is not consumed in the chemical reaction. However, catalysts do have an end of life and must be replaced. These projects replace the worn catalysts to achieve continued compliance with environmental permits. The projects will be completed in the second quarter of 2011 and cost APS a combined total of approximately $3.8 million.

E. *Focus on Cost Management*

Q. IS FOSSIL GENERATION FOCUSED ON COST MANAGEMENT?

A. Yes, cost management is a key part of Fossil Generation's business operations and an inherent result of the centralization efforts now underway. In mid-2009, shortly after I arrived at APS, I began the process of implementing a new operations model for the Fossil Generation business unit. Historically, the plants were run as individual entities, rather than as parts of a collective whole. The new fossil operations model (what we call the "FOM") moves to a one-fleet mindset, putting in place standardized policies and procedures designed to ensure that the fleet operates consistently, takes advantage of economies of scale and common resources, and works toward common goals. Much of the FOM reflects what we have determined to be best utility practices. This reorganization, now halfway complete, is improving the operational efficiency of the APS fossil fleet and providing cost management opportunities that benefit the business as a whole. In fact, these process changes resulted in a savings of at least $4.6 million in operational expenses during the 2010 Test Year.

Q. PLEASE PROVIDE SOME SPECIFIC EXAMPLES OF HOW THE NEW OPERATIONS MODEL CREATES EFFICIENCIES AND MANAGES COSTS.

A. A key aspect of the FOM is the use of benchmarking, metrics, and gap analysis. This process looks critically at what other fossil generators are doing in a given area so as to identify opportunities to improve our own operations, sets initiatives in place to drive process improvements, and establishes metrics used to measure performance. As part of this effort, in 2010, Fossil Generation took a critical look at its staffing and departmental structure and underwent an organizational redesign intended to improve operating efficiencies and implement a centralized fleet-focus. This reorganization resulted in, among other things:

- The creation of a new environmental operations department that centralized site environmental functions and created fleet-specific subject matter experts.

- The creation of an operations support department, which, among other things, centralized and standardized fleet-wide training programs and operational processes.

- A changed function for the engineering services department, from project design and management to plant operational and maintenance support.

- A transfer of the fuels department into the Fossil Generation business unit.

As a result of these and other organizational changes, the Company reduced its employee and consultant staffing levels by more than 10%.

Other process changes provide similar cost management opportunities. For example, in 2010, Fossil Generation implemented a capital project approval process, governed by a newly created Fossil Capital Approval Board (chaired by our Vice President of Fossil Operations). This process, modeled after a corresponding corporate process, sets forth guidelines intended to increase the transparency and scrutiny of project justification for Fossil Generation's capital spend, adopt a standardized approach to funding capital, incorporate a risk/opportunity analysis into capital spending decisions, and secure accountability for results. In addition, Fossil Generation's budgeting process for 2011 required a comprehensive review and detailed justification for all items proposed to be in the Fossil Operations budget, mandating approval of the proposed budget in its entirety rather than for increases from the prior budget year alone.

These examples are but a few that demonstrate Fossil Generation's contribution to the Company's aggressive focus on cost management.

Q. DOES FOSSIL GENERATION FACE ANY OTHER CHALLENGES?

A. Yes. APS, like other utilities and several other industries, is faced with the impact of an aging "baby boomer" workforce. Currently 34% of Fossil Generation's employees are eligible for retirement – a number that grows to almost 50% in 2014. With so many employees soon to retire, we have to plan now how to transfer knowledge to the continuing workforce. To address the potential knowledge gap, we have revitalized the Operations and Maintenance training program, started a summer internship for engineers, and implemented a Knowledge Transfer and Retention Procedure.

Another current challenge is managing our workforce through the changes that need to be made to transition to the current centralized organizational model. While we have seen improvements to areas of our operations as a result of this shift, we will not achieve our vision for operational excellence until those who work at our plants fully understand the need for and embrace the required change. Through focused communication, training, and demonstrated safety and operational improvements, we believe that all of our employees will support these policies and become champions of the new model.

IV. TOTAL FOSSIL GENERATION OPERATIONS AND CAPITAL REQUIREMENTS

A. *Total Capital Expenditures at the Fossil Plants.*

Q. WHAT WERE FOSSIL GENERATION'S NET PLANT ADDITIONS DURING THE TEST YEAR?

A. As illustrated in Standard Filing Requirement ("SFR") E-5, Fossil Generation added approximately $80 million in plant during the 2010 Test Year, bringing the business unit's total plant balance to approximately $3 billion.

Q. WHAT LEVEL OF PLANT ADDITIONS DOES FOSSIL GENERATION EXPECT THROUGH JUNE 30, 2012?

A. Attached to this testimony as MAS-1 is a detailed breakdown of the capital projects that will be in service as of June 30, 2012. As that exhibit shows, Fossil Generation expects to add a total of $156.3 million of plant by that date. These additions contribute $10.4 million to the Company's post-Test Year Plant adjustment, as detailed on SFR B-2, page 2, column 4. APS Witness Jason La Benz describes additional details of the adjustment, such as accumulated depreciation, accumulated deferred income taxes, depreciation expense, property taxes and interest expense.

V. BENCHMARK STUDY RESULTS FOR THE FOSSIL PLANTS

Q. EARLIER IN YOUR TESTIMONY YOU REFERENCED THE BENCHMARKING STUDY PREPARED BY LIBERTY CONSULTING GROUP. WOULD YOU LIKE TO ADDRESS ANY OF THAT REPORT'S RECOMMENDATIONS SPECIFIC TO THE FOSSIL PLANTS?

A. Yes. Although I generally accept the conclusions that Liberty reached relating to Fossil Generation, there are several areas where the report did not reflect information that we had provided– information that gives context to the results and that I believe deserves greater attention. Most significantly, Fossil Generation was already taking many of the action items that Liberty recommends. For example, in Recommendation 4.1, Liberty suggested that "APS should consider the implementation of a continuing program for analysis of outage causes." We implemented such a program in 2011. As Liberty suggests in Recommendation 4.2, Fossil Generation is now aligning its reporting practices with NERC GADS definitions, including the classification of maintenance outages. With respect to Recommendation 4.3, Fossil Generation commissioned a study in 2010 that addressed each of the points that Liberty raised. That study made several recommendations to improve plant performance, all of which have

been incorporated into Fossil Generation's operations model or 2011 Business Plan.

With respect to the higher than average forced outage rates at Four Corners, one cannot discount the negative impact that the quality of the coal used to fuel that mine mouth plant has on plant operations. Obviously, when one constructs a mine mouth plant, the coal quality cannot be improved by switching to another source of coal. Instead, one must evaluate the trade-offs of higher forced outage rates with less expensive, locally-mined coal. This point is underscored and explained in greater detail by Concentric Group ("Concentric"), which performed a deeper analysis of many the issues that Liberty identified in its report. That is not to say that substandard coal is the sole cause of Four Corners' above average forced outage rate. But, to the extent other factors contribute, Fossil Generation's recent process improvements should gradually correct past operational issues and improve plant performance going forward. Indeed, as Concentric notes in its report, data from 2009 and 2010 shows that the trend is now moving in the right direction.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS TO YOUR DIRECT TESTIMONY?

A. As I stated earlier, Fossil Generation's mission is to deliver superior operational performance while instilling a strong safety culture and protecting our environment. Although APS's fossil plants have performed well in the past, we are committed to operational excellence and have put in place the mechanisms that will drive future improvements where opportunities exist. Like other fossil-fueled generators in the industry, our fossil fleet faces significant challenges: among them, an aging workforce, aging assets, and ever-increasing laws and regulations that require expensive environmental upgrades. With a one-fleet

mindset, a standardized set of policies that reflect industry best practices, and a culture of continuous improvement and accountability, I firmly believe that we will navigate those challenges and continue to deliver cost-effective, reliable power to APS's customers and others throughout the Southwest.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Fossil Post-Test Year Plant Additions

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
1.	RHC0140	Redhawk Unit 2	Regulatory / Legislative / Contractual	GE LTSA CT Major Inspection	Scheduled overhauls are required to ensure reliable and safe operation of the gas turbine.	$ 29,016,657	$ 671,308	$ 29,687,965	3/29/2011
2.	FAC90173	Four Corners Units 1, 2, 3	Environmental Compliance	U1-3 5268 Lift Lined Ash Impoundment	The units must dispose of ash in order to operate. The embankments are raised in layers/lifts to minimize annual investment dollars.	$ 3,838,326	$ 4,034,346	$ 7,872,672	4/19/2011
3.	60-0819A	Navajo Units 1, 2, 3	Environmental Compliance	Low Nox Burners/Sep Overfired Air	Environmental / regulatory. NOx abatement modifications are being installed to meet presumptive Best Available Retrofit Technology (BART) levels of 0.22 lbs/mmBtu.	$ 5,259,081	$ 1,505,728	$ 6,764,809	4/3/2011
4.	60-0609	Navajo Units 1, 2, 3	Reliability	Gen Step-Up Transformer Replacement	Industry experience suggests that these long-term lead transformers will experience a rapidly increasing failure rate starting around 2014. These transformers are more than 30 years old. Failure of these units could cause loss of power generation for an extended period.	$ 4,230,759	$ 699,143	$ 4,929,902	4/3/2011
5.	CHC0310	Cholla Unit 1	Reliability	Horizontal Superheat Replacement	This project is to prevent tube leaks caused by cracking of tube to tube attachment welds, ash erosion that has progressed deeper into the bundles into inaccessible areas and related pad weld failures. Tube material will be conformed to current OEM standards, which are also cheaper than original design material. The average length of outage is four days due to access and repair constraints. This also can increase as tube leaks occur deeper into the tube bundles.	$ 50,032	$ 4,616,849	$ 4,666,881	4/29/2011
6.	CHC0317	Cholla Unit 3	Reliability	Platen Superheater Replacement	The purpose of this project is to maintain unit reliability by avoiding weld failures at tube/clip interface and the effects of long term overheating of the T11 material.	$ 28,093	$ 4,480,343	$ 4,508,436	4/27/2012
7.	CHC0320	Cholla Unit 3	Reliability	Economizer Replacement	The purpose of this project is to maintain unit reliability by reducing the risk for tube failures based on external erosion.	$ 16,144	$ 4,289,656	$ 4,305,800	4/27/2012
8.	CHC0242	Cholla Units 1, 2, 3	Reliability	Computer Predictive Perf Tools	Maintain heat rate, fuel usage and emissions thru improved operation of furnace / boiler.	$ 3,456,414	$ 159,930	$ 3,616,344	6/30/2011
9.	CHC0290	Cholla Unit 1	Reliability	L-1 LP Turbine Blade Replacement	This project is to replace the L-1 LP blades. The replacement is required based on a inspection where stress cracking was identified on some blades.	$ 447,599	$ 2,698,248	$ 3,145,846	4/23/2011
10.	RHC0088	Redhawk Unit 2	Prevent Failure	IP Turbine Blade Replacement	Ensure continued steam turbine reliability through the replacement of the IP blades during the upcoming major overhaul. New IP turbine shims and blades are required due to steam turbine shim migration and 1st and 2nd stage blade impact damage as evidenced by a bore-scope inspection.	$ 2,148,128	$ 931,784	$ 3,079,912	3/29/2011
11.	WPC0114	West Phoenix GT Units 1 & 2	Prevent Failure	GSU Transformer Replacement (T1687) U1-4	The GSU transformer is required to run the unit. T-777 was damaged during a synchronizing event on Unit 1 October 25, 2008, so it had to be replaced. With T-1483 in service there is no spare available. Lead time on a replacement transformer is approximately one year.	$ 2,760,092	$ 256,229	$ 3,016,321	5/10/2011
12.	RHC0104	Redhawk Unit 2	Safety / Security	2A & 2B Reheat Outlet Header Replacement	The piping to be replaced has been exposed to off-design thermal transients associated with steam attemperator spray water control leading to significant plastic deformation in the headers. The scoped piping is in an open-access area leaving Plant personnel exposed to any risk of failure in these components making this a safety priority.	$ 569,021	$ 2,134,369	$ 2,703,390	3/29/2011
13.	CHC0327	Cholla Unit 3	Environmental Compliance	Cooling Tower Drift Elim Replacement	The existing drift eliminators have become brittle and plugged and can not be cleaned to function as intended to capture water droplets. If the water droplets carried over to the atmosphere exceeds that allowed by the plant air permit the carry over is a unpermitted discharge and is in violation of EPA air pollution discharge permit.	$ 3,237	$ 2,623,989	$ 2,627,226	4/27/2012

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
14.	RHC0127	Redhawk Unit 2	Reliability	Cooling Tower Cells D Thru I Wood Replacement	The purpose of this project is to maintain unit reliability. Continued deterioration of the tower would result in collapse and unit curtailment. Improper construction by the original Manufacturer requires premature replacement of Cooling Tower structure components. Failing film fill and casing will be replaced at the same time as structure to save additional labor cost. FRP offers improved corrosion and fire resistance properties compared to wood. The FRP does not contribute harmful constituents to the cooing water compared to wood which leaches preservatives. The life expectancy of the FRP is approximately 40 years as compared to wood life expectancy of 15- 20 years. Replacement of structural members in only three cells rather than entire Cooling Tower is required to maintain continuous operations.	$ -	$ 2,621,954	$ 2,621,954	12/16/2011
15.	FAC90371	Four Corners Units 1, 2, 3	Environmental Compliance	Ash Pond Seepage Intercept	To intercept ash pond seepage.	$ 825,023	$ 1,542,183	$ 2,367,206	6/1/2011
16.	OCC0076	Ocotillo Stm Unit 1	Reliability	Cooling Tower Structure Improve	This project is to maintain the cooling tower structural integrity, preventing potential tower collapse and associated unit load curtailment.	$ -	$ 2,334,936	$ 2,334,936	3/11/2012
17.	OCC0077	Ocotillo Stm Unit 2	Reliability	Cooling Tower Structure Improve	The purpose of this project is to maintain the cooling tower structural integrity. Structural wood framing members and cell divider walls are in need of replacement.	$ -	$ 2,334,936	$ 2,334,936	3/16/2012
18.	WPC0117	West Phoenix CC 1	Reliability	Aux Cooling Water Piping Replacement	Pipe is corroding at an accelerated rate due to changes in cooling tower water chemistry.	$ 372,351	$ 1,688,276	$ 2,060,627	3/15/2012
19.	RHC0136	Redhawk Unit 2	Prevent Failure	Compressor Row Replacement	Excessive stator vane rock measured during the hot gas path inspection and confirmed during the 2009 borescope inspection places the compressor at risk of stator/blade liberation and failure.	$ 6,367	$ 1,975,941	$ 1,982,308	3/29/2011
20.	WPC0101	West Phoenix GT 2	Reliability	Inlet Cooler & Silencer Replacement	Inlet cooler and silencer are at end of life. Continued operation of existing equipment could result in cooler collapse and ingestion into the gas turbine causing damage.	$ -	$ 1,867,604	$ 1,867,604	5/18/2012
21.	WPC0100	West Phoenix GT 1	Reliability	Inlet Cooler & Silencer Replacement	Continued operation of existing equipment could result in cooler collapse and potential ingestion of the cooler components in the gas turbine causing damage.	$ -	$ 1,838,809	$ 1,838,809	2/9/2012
22.	CHC0298	Cholla Unit 2	Prevent Failure	Circ Water Line Steel Strand Replacement - In SVC 10/2010	The steel strand reinforcement of the pipe has corroded and inspection by a third party has revealed the troubled areas for repair with Carbon Fiber Replacement. The Circulating Water lines are essential to cool the steam cycle of the turbine/generator.	$ 1,670,004	$ 77,272	$ 1,747,276	6/30/2011
23.	CHC0337	Cholla Unit 2	Reliability	SGS Transformer 23A Replacement	The startup and general services transformer is necessary to start Units 2 and 3 and provide power to the common equipment for Units 1,2,3,4. The spare transformer replaced a damaged transformer in Aug 2010. This purchase will restore a spare to the inventory.	$ 918,807	$ 802,345	$ 1,721,152	10/29/2011
24.	60-0920M	Navajo Units 1 & 2	Reliability	Main Steam Piping Replacement Navajo 1-2	Metallurgical examination of the main steam piping concluded that a significant level of creep strain has occurred necessitating replacement of main steam piping from the crossover to the turbine connections during 2011 Major Overhaul. Generally, at 200,00 to 300,000 hours of operation, creep damage is to be expected at main steam conditions. NGS operating hours for Unit 1 is more than 250,000 hours to date.	$ 1,017,176	$ 515,418	$ 1,532,594	12/31/2011

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
25.	WPC0185	West Phoenix CC 5	Reliability	ZLD Vapor Washer	This project is to install a vapor washer down stream of the ZLD crystallizer body to eliminate safety related incidents and equipment down time. Currently, the ZLD operates below its designed operating level of 50% to stop foam from being carried over in the blower. The foam carryover has caused ZLD shutdowns and damage to the blower. If the ZLD system is abruptly shutdown, slurry begins to cool and solidifies in the piping. When this occurs, plant personnel are required to manually clear the semi-solidified slurry from the piping at elevated temperatures (225F). This has proven to be an unsafe operation leading to burn injuries. In addition, operating below the design level of 50% in the crystallizer has resulted in: Excessive wear on the circulation pump due to cavitation, a reduction in the retention time adversely affecting crystallization kinetics, finer crystals which are difficult to dewater, an increase in the Total Head (back pressure) TDH on the pump, reducing pump capacity, elevated temperatures in the heat exchanger that increases the rate of fouling.	$ -	$ 1,517,351	$ 1,517,351	3/23/2012
26.	60-0921	Navajo Units 1, 2, 3	Environmental Compliance	NE-1 Pond Refurbishment Nav 1-3	Construct a smaller north east 1 (NE-1) pond within the existing pond and install a new lining.	$ 1,184,769	$ 245,046	$ 1,429,814	6/30/2011
27.	RHC0100	Redhawk Units 1 & 2	Reliability	Well Water Pipe Installation	Complete the conversion of Redhawk RO System makeup from Makeup Pond water to well water. The existing temporary piping used to validate the conversion from pond to well water make-up has served its purpose and must be replaced. The temporary piping is above ground and presents a risk to personnel, a source of frequent line leaks, and a deterrent to efficient and productive work flow and access around the cooling towers. Installing a permanent piping system underground will alleviate these concerns as well as provide a permanent source of RO makeup.	$ 136,739	$ 1,281,694	$ 1,418,433	3/23/2011
28.	WPC0106	West Phoenix CC 5	Reliability	HRSG Drain 5B Upgrade	This project is to reconfigure/redesign the drain lines from the Heat Recover Steam Generator to the condensate flash tank. Currently, the existing drain line configuration does not allow condensate to gravity flow to the condensate flash tank. This condition allows quenching of the superheater and reheater tubing sections.	$ 66,744	$ 1,331,801	$ 1,398,545	12/5/2011
29.	WPC0105	West Phoenix CC 5	Reliability	HRSG Drain 5A Upgrade	This project is to reconfigure/redesign the drain lines from the Heat Recover Steam Generator to the condensate flash tank. Currently, the existing drain line configuration does not allow condensate to gravity flow to the condensate flash tank. This condition allows quenching of the superheater and reheater tubing sections.	$ 73,873	$ 1,294,795	$ 1,368,668	12/5/2011
30.	CHC0294	Cholla Unit 3	Prevent Failure	Circulating Water Line Replacement	The inlet and discharge lines are in poor condition and will require either replacement or major repair effort.	$ -	$ 1,275,592	$ 1,275,592	4/27/2012
31.	WPC0181	West Phoenix CC 3	Reliability	Evap Cooler Replacement	Extensive corrosion of the evaporative cooler and collection basins could allow water to leak from the contained area onto the ground which would not comply with the Aquifer Protection Permit. Corrosion has produced holes in the evaporative cooler enclosure which can allow debris to bypass the filtration and potentially enter the turbine. This debris would increase wear and decrease the life of the turbine components.	$ 23,514	$ 1,217,203	$ 1,240,717	4/15/2011
32.	CHC0289	Cholla Unit 2 & 3	Reliability	Acoustic Monitoring System	The system provides indication of small leaks that occur, so that the management of forced outage timing can be scheduled to minimize economic impact to the system. An additional advantage of this system is that it minimizes the probability of a forced outage occurring immediately following startup because all leaks can be identified going into an outage.	$ 166,078	$ 1,060,760	$ 1,226,838	7/1/2011
33.	RHC0091	Redhawk Unit 2	Environmental Compliance	HRSG SCR Catalyst Replacement	This project is to replace the SCR catalyst to ensure continued compliance with the Title V air permit requirements. Catalyst is replaced when the need is shown by testing.	$ 327,797	$ 883,178	$ 1,210,974	3/29/2011

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
34.	WPC0167	West Phoenix CC 2	Reliability	CC2 - Evap Cooler Replacement	Extensive corrosion of the evaporative cooler and collection basins could allow water to leak from the contained area onto the ground which would not comply with the Aquifer Protection Permit. Corrosion has produced holes in the evaporative cooler enclosure which can allow debris to bypass the filtration and potentially enter the turbine. This debris would increase wear and decrease the life of the turbine components.	$ 396	$ 1,185,061	$ 1,185,457	3/25/2011
35.	WPC0151	West Phoenix CC 3	Prevent Failure	HRSG Economizer Replacement	Oxygen corrosion pitting caused by cyclic operation has compromised unit performance. Continued operation could damage the new SCR catalyst resulting in early replacement and increasing the number of forced outages due to tube leaks.	$ 698,541	$ 474,900	$ 1,173,441	4/15/2011
36.	SDC0049	Sundance Units 1-10	Reliability	Control System Upgrade	The purpose of this project is to replace the existing Turbine Flow and Speed Control System with an Enhanced Flow and Speed (EFS) Control System. This upgrade will maintain heat rate and power output, and optimize Sprint and NOX water control and upgrade the fuel core controls.	$ -	$ 1,120,556	$ 1,120,556	12/16/2011
37.	WPC0187	West Phoenix CC 5	Reliability	5A Rotor Air Cooler Replacement	The purpose of the project is to replace the rotor air cooler. The original rotor air cooler has experienced multiple tube failures and was eventually retubed. The original design for the rotor air cooler did not account for the high number of thermal cycles associated with cyclic operation and the tubesheet is showing signs of fatigue failure.	$ -	$ 1,080,521	$ 1,080,521	3/23/2012
38.	CHC0308	Cholla Common	Environmental Compliance	Mercury Vapor Lighting Replacement	Regulatory compliance requires all mercury vapor fixtures to be removed.	$ 701,187	$ 370,833	$ 1,072,019	2/26/2011
39.	RHC0147	Redhawk Unit 1	Environmental Compliance	Attemperator Replacement	The purpose of this project is to maintain safe operation of the unit by replacing the damaged hot reheat steam attemperators. The inner liners of the attemperator piping have failed allowing quenching water to contact the pressure boundary, resulting in visible piping deformation. The attemperator assemblies will be replaced during the current Unit 1 outage and a piping health study will be conducted under the WA to find the root cause of the damaged piping. Solutions will be implemented based on the findings of the root cause investigation to prevent future attemperator and associated piping damage.	$ 996,610	$ 46,114	$ 1,042,724	6/30/2011
40.	CHC0325	Cholla Unit 3	Prevent Failure	Cooling Tower Upgrade	Replace wooden structure members in 3 cells with FRP structural member upgrades. This work does not include fan deck and hot deck which have already been upgraded to FRP. Repl distribution valves.	$ -	$ 1,018,580	$ 1,018,580	4/27/2012
41.	WPC0131	West Phoenix CC 5	Prevent Failure	Condenser Modification Upgrade	The purpose of this project is to eliminate excessive water transport to the steam turbine L-0 blades during low load operating conditions. Excessive amount of water and water droplet size has caused accumulated trailing edge erosion on steam turbine L-0blades. This is based on an inspection done by Siemens and a study by Yuba condenser division. The condenser retrofit would be completed during the 2011 spring outage. Note: Siemens has installed new L-0 in the recent spring overhaul of 2010. The new blades will address tip cracking which is the subject of a warranty claim. However, Siemens is concerned with the amount of trailing edge erosion and has postulated that the condenser design could be causing the condition.	$ 118,932	$ 878,287	$ 997,219	1/29/2011
42.	WPC0155	West Phoenix CC 5	Environmental Compliance	CC5A SCR Catalyst	The purpose of this project is to replace the SCR catalyst to ensure continued compliance with the Title V air permit requirements. Catalyst must be replaced every 5 to 7 years in order to ensure proper performance. Lead time for catalyst is currently 12 months. This project must coincide with the gas turbine major overhaul.	$ 579,123	$ 359,414	$ 938,538	2/12/2011
43.	WPC0179	West Phoenix CC 1	Reliability	1st Stage Bucket Replacement	The purpose of this project is to replace the first stage buckets in accordance with the OEM recommended maintenance schedule.	$ -	$ 921,116	$ 921,116	3/15/2012
44.	WPC0178	West Phoenix CC 2	Reliability	1st Stage Bucket Replacement	The purpose of this project is to replace the first stage buckets in accordance with the OEM recommended maintenance schedule.	$ -	$ 917,565	$ 917,565	2/24/2012

Fossil Post-Test Year Plant Additions

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
45.	CHC0356	Cholla Common	Reliability	Cable Tray & Cable Replacement, Phase 5	Purpose of this project is to maintain the integrity of this portion of the auxiliary power system. This is part of a long range plan to replace all critical 5KV feeder cables with cables contained in overhead cable tray. The underground cable for the 3A3 feeder faulted and is no longer useable.	$ -	$ 917,159	$ 917,159	4/29/2011
46.	WPC0077	West Phoenix CC 5	Environmental Compliance	5B SCR Catalyst	The purpose of this project is to replace the SCR catalyst to ensure continued compliance with the Title V air permit requirements. Catalyst must be replaced every 5 to 7 years in order to ensure proper performance. This project must coincide with the gas turbine major overhaul.	$ 586,254	$ 313,286	$ 899,541	1/28/2011
47.	WPC0180	West Phoenix CC 1, 2, 3	Safety / Security	Cooling Tower Fan Deck Replacement	The existing treated plywood deck has been inspected and needs to be replaced to ensure structural integrity of the tower structural diaphragm (fan deck) and provide a safe walking surface for plant personnel.	$ -	$ 889,330	$ 889,330	12/15/2011
48.	WPC0198	West Phoenix CC 1	Reliability	1st Stage Spare Nozzle	The purpose of this project is to replenish the critical (long lead) spare parts inventory. The warehouse spare 1st Stage Nozzle was recently installed in CC1.	$ -	$ 885,122	$ 885,122	3/15/2012
49.	CHC0336	Cholla Unit 2	Reliability	Auxiliary Transformer Replacement	This project will enable operation of the unit without having to reduce load on Unit 3 when starting Unit 2, and reduce chance of overload of startup bus if Unit 3 trips when Unit 2 is operating, if Unit 2 auxiliaries are fed from the startup bus.	$ 368,743	$ 504,293	$ 873,036	4/23/2011
50.	WPC05916	West Phoenix CC 2	Reliability	Aux Cooling Water Piping Replacement	Pipe is corroding at an accelerated rate due to changes in cooling tower water chemistry. Piping system components were originally designed for two cycles of concentration. Plant is currently operated at seven cycles of concentration which results in a chloride level greater than what carbon steel can handle.	$ -	$ 841,439	$ 841,439	2/24/2012
51.	RHC0128	Redhawk Unit 2	Reliability	Cooling Tower Drift Elim Cells D - I Replacement	This project is to redesign and replace the existing drift eliminators that are cracked and sagging. This will eliminate the potential of excessive drift and maintain compliance with regulations.	$ -	$ 841,201	$ 841,201	12/16/2011
52.	RHC0106	Redhawk Unit 1	Reliability	Cooling Tower Drift Elim Cells D -	This project is to redesign and replace the existing drift eliminators that are cracked and sagging. This will eliminate the potential of excessive drift and maintain compliance with regulations.	$ 2,806	$ 816,351	$ 819,156	12/16/2011
53.	FBC90366	Four Corners Units 4 & 5	Environmental Compliance	Dry Fly Ash Disposal Area Phase 2	Ash Disposal at Four Corners converted from mine disposal to an onsite area fill in 2006 to save hauling and operational expenses. The existing landfill may be over capacity in 2011. Initial expense includes the evaluation of onsite disposal alternatives to manage potential environmental issues associated with coal combustion products.	$ 333,343	$ 464,159	$ 797,502	10/4/2011

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
54.	FAC90382	Four Corners Unit 2	Reliability	Mill Bull Gear Replacement	This project is to replace the main ring gear and matching pinion gear to maintain Unit reliability. This bull gear has been in service since 1962. The Spring 2010 inspection found a severely damaged gear and pinion. The inspection report and the associated risk analysis both recommended replacement.	$ 1,649	$ 794,874	$ 796,522	10/8/2011
55.	FAC90377	Four Corners Unit 1	Reliability	Mill Bull Gear Replacement	This Bull Gear has been in service since 1962 and was reversed in 1988. The second side of the gear teeth are now worn and at end of life.	$ 7,072	$ 780,093	$ 787,165	12/16/2011
56.	60-1059	Navajo Units 1, 2, 3	Reliability	Water Wall Repair-2	NGS Unit 2 suffered a major furnace waterwall tube temperature excursion forced outage event in 2006. A waterwall tube inspection and condition assessment was performed during the 2007 minor overhaul. The inspection showed that the overheating event clearly induced a significant amount of permanent deformation as evidenced by buckling of the tube panels in both the transverse and longitudinal directions. This project will repair waterwall tubes damaged during the 2006 Unit 2 overheating event.	$ 748,382	$ 34,628	$ 783,010	6/30/2011
57.	FBC90405	Four Corners Unit 4	Reliability	Partial Economizer & Reheat Replacement	The high ash loading combined with the high gas velocity in the Unit 4 convection pass has resulted in erosion in parts of the Economizer and Horizontal Reheater. This project will replace the Economizer and Horizontal Reheater elements that are subjected to the worst erosion. A coating designed to reduce the ash erosion will be applied to portions of both the Economizer and Horizontal Reheater elements.	$ 700,032	$ 32,391	$ 732,423	6/30/2011
58.	WPC0119	West Phoenix CC 4	Environmental Compliance	CO Catalyst	The purpose of this project is to replace the CO catalyst to ensure continued compliance with the Title V air permit requirements. Catalyst is replaced based upon testing results.	$ -	$ 726,991	$ 726,991	10/16/2011
59.	CHC0312	Cholla Common	Reliability	Maximo Consolidation	A common structure will eliminate the need to migrate changes from one environment to the other two to support new requirements or resolve issues. Four Corners has committed to using Maximo to organize work flow. Upgrading will allow Four Corners to keep up with the Maximo long range strategy and minimize future upgrade expense.	$ 714,987	$ 5,514	$ 720,501	1/10/2011
60.	CHC0332	Cholla Common	Environmental Compliance	Fly Ash Silo Vent Filter	The fly ash silo vent filters are to be resized to meet new ash flow requirements into the silo. The ash silo vent filters are essential to unit operation.	$ -	$ 712,473	$ 712,473	4/20/2012
61.	YUC0064	Yucca GT 1, 2, 3, 4	Reliability	#4 Well Install (APS Share) 2011	Ensure reliable raw water supply to the Yucca Power Plant, including IID's Yucca Unit 1. Existing well has been in service many years. The casing has corroded to extent that well reliability is difficult to ensure.	$ -	$ 711,464	$ 711,464	12/9/2011
62.	WPC0074	West Phoenix CC 3	Environmental Compliance	SCR Catalyst Replacement	This project is to replace the SCR catalyst to ensure continued compliance with the Title V air permit requirements. Catalyst is replaced when the need is shown by testing.	$ -	$ 707,751	$ 707,751	4/15/2011
63.	CHC0273	Cholla Common	Safety / Security	Undgrnd Potable Water Pipe Replacement Ph	The purpose of this project is to maintain a reliable potable water supply to the Plant and outlying facilities. The existing supply mains were designed and installed with the Units in the 1970s. It is suspected that erosion/corrosion of the pipe wall is causing leakage in some areas. Additionally, users have been added to the system and an engineering study has shown that that the existing head tank cannot supply the pressure necessary for current system demands. Collectively, these conditions may create an unreliable and inadequate water supply.	$ 332,290	$ 365,439	$ 697,729	2/25/2011
64.	CHC0300	Cholla Common	Environmental Compliance	BA East Monofill Expansion Ret Basi	To expand the existing monofill in order to continue Plant operations in compliance with the Aquifer Protection Permit (APP).	$ 50,362	$ 645,666	$ 696,028	12/15/2011
65.	WPC0135	West Phoenix CC 5	Safety / Security	Cooling Tower Fan Deck Replacement	The existing treated plywood deck is showing signs of deterioration and will need to be replaced to ensure structural integrity of the tower structural diaphragm (fan deck) and provide a safe walking surface for plant personnel.	$ -	$ 680,076	$ 680,076	12/16/2011

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
66.	SDC0048	Sundance Units 1-10	Reliability	Permanent Water Rights Purchase	Purchase of Central AZ Water Conservation District (CAWCD)(CAP) water rights from the Gila River Indian Community. Sundance is currently using CAP Excess water. If a shortage is declared on the Colorado River Sundance is in jeopardy of losing that water.APS needs a secure water supply to ensure Sundance can operate when called upon to do so.	$ -	$ 627,762	$ 627,762	12/15/2011
67.	60-0922	Navajo Units 1, 2, 3	Safety / Security	Coal Flame Scanners Navajo 1-3	Purchase and install a new generation of coal flame scanners.	$ 433,069	$ 162,396	$ 595,464	3/4/2012
68.	FCC90393	Four Corners Common	Prevent Failure	Coal Sample AB Surge Bin Cone Replacement	The existing surge bin has worn out. This project is to replace the coal sample A and B surge bin cones for Units 4 and 5, maintaining unit reliability.	$ -	$ 593,244	$ 593,244	10/29/2011
69.	CHC0272	Cholla Common	Reliability	Condensate Transfer System Upgrade	The purpose of this project is to provide flexibility to transfer condensate between Units 1-4 in order to prevent Unit load curtailments due to condensate contamination and loss of condensate resulting from underground pipe corrosion and failure.	$ 386,481	$ 183,219	$ 569,700	3/31/2011
70.	CHC06425	Cholla Common	Regulatory / Legislative / Contractual	Flyash Slurry C Line Replacement	The purpose of this project is to ensure Unit availability through continued serviceability of the bottom ash pond. The "C" slurry pipe line is integral to maintaining the ash pond water level in that it transfers excess water from the bottom ash pond to he fly ash pond during the winter months when pond evaporation rates are diminished. Without the "C" slurry line in service, eventual shutdown of all Units would be required to remain in compliance with APP Permit requirements and ADWR Dam Safety Requirements.	$ -	$ 564,244	$ 564,244	2/28/2011
71.	FAC90206	Four Corners Unit 1	Reliability	U1 Scrub Plumb Bob Shaft Dent Bowl	This project is to replace the existing 316L stainless steel shafts with 317L stainless steel, and to design and install a lateral support and Dentist Bowl. The scrubber plumb bob shafts are failing at the top of the shaft due to fatigue and near the unin of the shaft and the plumb bob due to stress corrosion cracking. 317L stainless steel has greater resistance to corrosion and a higher tensile strength which will reduce the chances of stress corrosion cracking and fatigue failure. The support will be installed into the scrubber vessel walls and restrain shaft oscillation. The support, coupled with the superior material properties of the 317L should effectively eliminate these types of failures.	$ 8,034	$ 550,976	$ 559,010	12/16/2011
72.	60-1091	Navajo Units 1, 2, 3	Reliability	Long Lead Time Material Purchase-1	Overhaul start dates have been moved forward to January. This creates a logistical problem for direct purchase materials. Maintenance personnel want the materials on-site well ahead of the outage, so they have the ability to react to any problems. Holidays affect NGS's ability to ship, receive, and pay for these materials. Overhaul materials have long lead times and need to be purchased ahead of the outage to ensure availability. NGS expects to purchase" between 30% and 50% of the materials required for the Unit 1 Major Overhaul to be delivered in 2010, prior to the scheduled outage. Specific materials identified because of known lead time issues include 1 st and 7th stage buckets for the main turbine ($0.7 million) and Platen Superheater pendent tube materials ($0.2 million).	$ 161,819	$ 392,495	$ 554,314	6/30/2011
73.	CHC0319	Cholla Unit 2 & 3	Reliability	Boiler, Turb Elev Controls Replacement	Make the Boiler and Turbine Bldg Elevators more reliable and avoid delays in productivity or return to service. Controls are to be replaced in compliance with ASME/ANSI A17.1 and 17.3, which require replacement rather than modification with non-OEM part.	$ -	$ 547,268	$ 547,268	11/1/2011
74.	RHC0143	Redhawk Common	Prevent Failure	RO Membrane Replacement - DELAYED	Expected life for 1st pass membranes is 3-5 years, second pass membranes need to be changed every 5-7 years.	$ -	$ 531,574	$ 531,574	4/1/2012

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
75.	CHC0299	Cholla Common	Reliability	Plant Microwave System Upgrade	The existing system is experiencing reduced reliability and its bandwidth will be overloaded when all the security monitoring and control requirements are met throughout the existing system. The requirements to handle the critical control and data monitoring, security video information and business network communications will exceed the existing communications infrastructure capabilities. The Cholla switchyard is considered a high security area in alignment with the permanent Cyber Security Standard – Critical Infrastructure Protection Reliability Standards CIP-002-1 through CIP-009-1 which replaced the NERC 1200 Standard and was adopted in June 2006.	$ 34,206	$ 478,660	$ 512,866	7/12/2011
76.	RHC0135	Redhawk Unit 2	Reliability	Expansion Joint Replacements	To maintain unit reliability.	$ 8,996	$ 496,174	$ 505,170	3/29/2011
77.	CHC0297	Cholla Common	Safety / Security	Plant Paving, South Rd,Entr Rd Replacement	The current roads have deteriorated. The paving needs be done after the environmental improvements have been completed.	$ 226,127	$ 278,417	$ 504,544	6/8/2011
78.	FCC90365	Four Corners Common	Reliability	Maximo Consolidation	A common structure will eliminate the need to migrate changes from one environment to the other two to support new requirements or resolve issues. Four Corners has committed to using Maximo to organize work flow. Upgrading will allow Four Corners to keep up with the Maximo long range strategy and minimize future upgrade expense.	$ 455,658	$ 48,350	$ 504,008	1/11/2011
79.	WPC0141	West Phoenix CC 3	Prevent Failure	BFP Warehouse Spare	The purpose of this project is to provide a boiler feed pump, to be utilized as a warehouse spare in the event of a BFP failure and subsequent loss in Unit generation capacity. The existing OEM in-service BFP's are more than 30 years old, and each have experienced an increasing rate and extent of repairs over the last 15-years of service, increasing the risk of BFP failure.	$ 275,304	$ 192,284	$ 467,588	4/15/2011
80.	WPC0191	West Phoenix CC 5	Reliability	Cooling Tower Fan Purchase	This project is to replace the cooling tower fans with in-kind units to ensure reliable and safe operation of the cooling tower. Existing fans hubs are showing advanced signs of corrosion.	$ -	$ 464,236	$ 464,236	10/7/2011
81.	RHC0093	Redhawk Unit 2	Prevent Failure	Perf Plates and Supports Replacement	The project is to eliminate the on going cyclic fatigue/failure of the existing perforated plates and supports within CC2 HRSG's. This will require having Vogt Engineering redesign the existing perforated plates and supports. The new replacements would be installed during the 2011 major outage.	$ 129,831	$ 322,993	$ 452,824	3/29/2011
82.	60-0908	Navajo Units 1, 2, 3	Safety / Security	Main Turb Bearing-Underflr Fire Sup	Upgrade the main turbine and fire suppression system. Install heat detection and sprayers on the bearings. Install an underfloor wet pipe fire protection system. Upgrade the diesel fire pump.	$ 313,934	$ 135,733	$ 449,667	4/3/2011
83.	YUC0069	Yucca GT 3	Safety / Security	Cardox Tank Replacement	The purpose of this project is to replace the existing rusted Cardox tank with a new tank and controls. This is based on a recommendation by HSB during a fire inspection.	$ 11,080	$ 436,327	$ 447,407	2/18/2011
84.	60-1115C	Navajo Common	Reliability	Op Emg,Cap Ex,Spare Pts Contingency	This budget item is to cover unforeseen capital expenditures which arise during 2011, and to comply with sections 15.2 and 17.1 of the Navajo Generating Station Operating Agreement. Examples of past expenditures from this line item include the purchase of an audiometer and a generator step-up transformer dissolved gas analyzer, and installing a ventilation system for the tool room.	$ -	$ 429,766	$ 429,766	12/31/2011
85.	60-1116C	Navajo Common	Reliability	Plant Tools Contingency	This budget item is to cover capital expenditures which arise during 2011. Examples of past expenditures from this line item include the purchase of hot water pressure washer, a breaker trip test kit, a pipe threader and Huck railroad tools.	$ -	$ 429,766	$ 429,766	12/31/2011
86.	YUC0070	Yucca GT 4	Safety / Security	Cardox Tank Replacement	The purpose of this project is to replace the existing rusted Cardox tank with a new tank and controls. This is based on a recommendation by HSB during a fire inspection..	$ 4,203	$ 424,780	$ 428,982	4/2/2011

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
87.	WPC0190	West Phoenix CC 5	Safety / Security	Steam Turb Cond Flash Tank Replacement	This project is to replace the condensate flash tank. The current tank has significant deterioration and must be replaced. Without this tank in service the unit cannot operate.	$ -	$ 417,462	$ 417,462	12/5/2011
88.	60-1101M	Navajo Unit 1	Reliability	Ash System - U1 Major Overhaul	To upgrade the Bottom Ash system to enable the continued operation of the collection and removal system. The unit cannot operate if the bottom ash is not removed from the boiler.	$ -	$ 417,095	$ 417,095	4/3/2011
89.	CHC0324	Cholla Unit 3	Reliability	BFP Component Rotating Element Replacement	Restore worn pump, valve, fluid coupling, and piping to reliable operating condition. Replace check valve if necessary.	$ -	$ 416,886	$ 416,886	4/20/2012
90.	CHC0306	Cholla Common	Prevent Failure	Cathodic Protection Sys 9, 10, 11,	The depleted cathodic protection systems must be replaced to preserve underground assets, reduce maintenance costs, comply with government regulations, and preserve the environment.	$ 206,263	$ 204,708	$ 410,971	12/10/2011
91.	FAC90281	Four Corners Unit 2	Reliability	ID Fan Scroll Replacement	The purpose of this project is to ensure the continued full load reliability of Unit 2. Existing scrolls, including the cut off points ("bull nose") of the fans, are exposed to a harsh, corrosive service environment. The extent of damage to the existing scrolls and cut off points renders further interim repairs ineffective, therefore necessitating the need to replace the scroll.	$ 360,717	$ 49,841	$ 410,558	6/30/2011
92.	WPC0113	West Phoenix Common	Safety / Security	Fire Alarm Panel Replacement	The purpose of this project is to reduce response time and alert personnel from entering unsafe locations.	$ 394,854	$ 9,068	$ 403,922	1/12/2011
93.	FCC90303	Four Corners Common	Reliability	Local Area Network Switch Upgde	The purpose of this project is two fold: 1) to increased demand of the capture, storage and delivery of process systems data for systems like CEMS, Data Historians, Neural Networks and other business applications; 2) to increase performance to support more demanding applications including voice over IP communication and faster PC system demand.	$ 235,063	$ 147,373	$ 382,436	5/13/2011
94.	FCC90267	Four Corners Common	Reliability	Plant Perimeter Security Upgde	The purpose of this project is to eliminate any unauthorized access to Plant equipment.	$ 350,684	$ 29,465	$ 380,149	3/9/2011
95.	60-1154	Navajo Unit 2	Environmental Compliance	Sootblower Upgrade-2	The 360 degree spray rotation and close proximity of the 29R and 30R sootblowers to the upper bullnose slope cause severe sootblower erosion and thinning of the water wall tube failures and forced outages.	$ 32,221	$ 342,967	$ 375,188	4/3/2011
96.	CHC0275	Cholla Common	Safety / Security	Fire Water System Upgrade	This will prevent future leaks and control valve failures and the associated repair cost, as well as the loss of fire water supply.	$ 48,856	$ 324,100	$ 372,955	6/15/2011
97.	WPC06115	West Phoenix CC 5	Reliability	Cooling Twr Mech Equip Access Walkways	Allow safe access to fan assemblies mechanical equipment.	$ -	$ 369,222	$ 369,222	3/23/2012
98.	FAC90324	Four Corners Unit 1	Reliability	1st Stage Turbine Buckets Replacement	The purpose of this project is to mitigate lost generation and replacement power cost. The 1st stage high pressure buckets, installed in 1997, have a probability of damage when removed on critical path in 2011 to inspect and repair cracks in the axia face of the rotor dovetails.	$ 150,696	$ 202,037	$ 352,732	12/16/2011
99.	FBC90297	Four Corners Units 4 & 5	Environmental Compliance	5268 Lift Lined Ash Impoundment	The units must dispose of ash and process water or they cannot operate. The embankments are raised in lifts to minimize annual investment dollars.	$ 213,333	$ 121,770	$ 335,103	4/19/2011
100.	YUC0062	Yucca GT Units 1 & 2	Reliability	AVR Replacement	The purpose of this project is to replace the old, original GE AVR with a new AVR and PSS.	$ -	$ 334,406	$ 334,406	3/16/2012

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
101.	WPC0091	West Phoenix CC 1, 2, 3	Environmental Compliance	Lube Oil Mist Eliminator	The purpose of this project is to ensure continued operational compliance within the opacity limits defined in the Title V air permit. The current mist eliminators require replacement. This is an environmentally related project.	$ -	$ 315,014	$ 315,014	3/11/2011
102.	WPC0177	West Phoenix CC 1, 2, 3	Reliability	Cooling Tower Drift Eliminators Replacement	Maintain environmental compliance with Plant air operating permit.	$ -	$ 313,881	$ 313,881	12/15/2011
103.	OCC0078	Ocotillo Common	Reliability	General Svcs Transformer T492 Replacement	Provide unit reliability. T492 has been deemed a critical transformer since it is the normal path to start up the steam units and provide aux power to the gas turbines. The present transformer is approaching the end of its useful life based on recent testing results. Gas-in-oil tests are in the normal range as of the kickoff date but several different gasses have shown elevated levels over the last three years.	$ -	$ 311,568	$ 311,568	10/29/2011
104.	60-1166M	Navajo Units 1, 2, 3	Reliability	Plant Piping Replacement	Portions of the original above ground and underground piping is near the end of its service life in many areas of the plant. Since 1994, NGS has undertaken a systematic annual program to replace and move piping above ground. As of 2009, NGS replaced approximately 66,500 feet of pipe. Work is scheduled and completed based on condition. Past budgetary postponements of plant piping work due to overruns in other areas have resulted in steadily increasing maintenance in instrument air, cooling tower blow down, oily waste, and other lines that remain below the surface. This budget includes funding to continue work on firewater, oily water, potable water, service water, service air, and instrument air lines. Work will be performed on underground piping on the east side of the boilers.	$ -	$ 291,930	$ 291,930	12/31/2011
105.	CHC0302	Cholla Common	Reliability	Lime Swgr,Recvng Whse Bldg Roofs Re	The purpose of this project is to maintain unit reliability.	$ 14,221	$ 276,516	$ 290,737	6/1/2011
106.	WPC0211	West Phoenix CC 5	Safety / Security	Main Steam Flow Nozzle Replacement	The existing flow elements contain a dissimilar metal weld which is susceptible to cracking under cyclic operation. Service Bulletins have been released by the manufacturer and Alstom identifying the potential for personal injury and equipment damage. Approximately ten failures have been reported.	$ -	$ 272,042	$ 272,042	12/5/2011
107.	RHC0139	Redhawk Units 1 & 2	Reliability	Lube Oil Varnish Mitigation	Redhawk has experienced servo valve failures due to oil varnish (sludge) contamination. The industry has alluded that diminished solubility of the now standard Group 2 oil has resulted in higher degradation of the oil additives. Ultimately, this becomes the main avenue for the formation of varnish within the system. This is especially a quality associated with the GE Frame 7 turbine which are subjected to high cycling operation. The varnish does not become an operating problem until the oil can no longer hold it in solution. Once this occurs, varnish begins to agglomerate throughout the lube oil system. It plates out on the reservoir, piping, and control valves and causes problems in operation. Technological advancements have allowed for the creation of Varnish Mitigation Technology that addresses the problem while in solution, preventing insoluble varnish from occurring.	$ 212,988	$ 44,233	$ 257,222	1/17/2011
108.	WPC0164	West Phoenix Common	Reliability	Boiler Maint Tracking Software	The purpose of this project is to maintain good condition assessment and repair information on the HRSGs.	$ 168,373	$ 81,618	$ 249,990	1/31/2011
109.	FBC90369	Four Corners Unit 5	Reliability	DCS Pwr Supply & Amm Hardware Replacement	The purpose of this project is to restore ABB DCS hardware reliability in order to maintain Unit reliability. The parts are no longer available or supported by the original equipment manufacturer. Attempts to replace through third party sources have been unreliable.	$ 65,558	$ 183,011	$ 248,569	4/22/2011

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
110.	FBC90328	Four Corners Unit 5	Reliability	Aux Turbine Prot Upgrade	The purpose of this project is to improve the Auxiliary Turbines protection instrumentation, monitoring, and control system to maintain reliability, performance and protection. A new EHC oil system is needed along with new actuators to control the turbine seeds. The mechanical overspeed bolt will be replaced with triple redundant overspeed controls. New aux turbine supervisory instrumentation will be included for better monitoring and control of vibration, eccentricity, rotor positioning.	$ 97,776	$ 148,797	$ 246,572	4/15/2011
111.	CHC0276	Cholla Common	Reliability	Service-Instrument Air Pipe Replacement	Plant personnel have had to repair and/or replace portions of the Service/Instrumentation Air system because of leaks that have occurred.	$ 131,292	$ 114,508	$ 245,800	2/25/2011
112.	CHC0291	Cholla Units 1, 2, 3	Environmental Compliance	Old Ash Pond Bank Stabilization	Stabilize ash pond bank.	$ 48,317	$ 191,857	$ 240,175	7/11/2011
113.	SDC0042	Sundance Units 1-10	Prevent Failure	RO Membrane Replacement	1st pass membranes need to be replaced every 3 to five years and second pass membranes need to be replaced every 5 to 7 years.	$ 7,062	$ 229,793	$ 236,855	6/20/2012
114.	60-0909	Navajo Units 1, 2, 3	Environmental Compliance	Scrubber Mist Eliminator Upgrade	The purpose of this project is to replace the existing mist eliminators with a more effective design made from a more durable material.	$ 146,416	$ 84,410	$ 230,826	4/3/2011
115.	WPC06113	West Phoenix CC 1, 2, 3	Reliability	Cooling Twr Mech Equip Access Walkways	Safely accessing cooling tower equipment, provide inspection, and decrease construction schedule.	$ -	$ 227,603	$ 227,603	3/12/2012
116.	CHC0245	Cholla Units 1, 2, 3	Reliability	Boiler Maint Tracking Software	The purpose of this project is to maintain the frequency and length of boiler tube leak outages by maintaining good condition assessment and repair information on the boilers.	$ 217,308	$ 10,055	$ 227,363	6/30/2011
117.	WPC0205	West Phoenix CC 1	Prevent Failure	BFP Recirculation Piping Redesign	The purpose of this project is to redesign the Unit 1 boiler feed pump recirculation system to eliminate cavitation within the pump thereby reducing premature pump failure and maintaining unit reliability.	$ 27,600	$ 197,692	$ 225,292	3/25/2011
118.	OCC0072	Ocotillo Stm Units 1 & 2	Environmental Compliance	Circ Water Acid Tank Replacement	The purpose of this project is to replace the corroded steel acid storage tank with a corrosion resistant XLHDPE Double Wall tank. Wall thickness measurements taken in January 2010 indicate areas of serious thinning on the south side of the tank, tinning of the bottom, and significant buildup of corrosion products on the interior surface. Should a leak occur, there is the potential for a spill with associated safety issues due to the hazardous nature of Sulfuric acid. The tank is used to control the ph of the circulating water.	$ 21,305	$ 196,086	$ 217,391	3/31/2011
119.	CHC0318	Cholla Unit 2	Prevent Failure	Station Battery Charger Replacement	The purpose of this project is to maintain reliable source to charge unit batteries for the 125VDC distribution system. The battery chargers are plant original equipment (1981) and are at the end of life.	$ 142,409	$ 73,599	$ 216,008	3/4/2011
120.	WPC0175	West Phoenix Common	Reliability	RO Membrane Replacement	To maintain quality water required for plant operations.	$ 186,644	$ 28,543	$ 215,187	1/18/2011

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
121.	60-1066	Navajo Units 1, 2, 3	Reliability	Plant Piping Replacement-Com	The underground utility replacement project was started in 1993. The plant was broken up into 23 zones. The majority of these are outside the main power block area. Initially, pipe failures were occurring frequently in the out-lying areas around the Cooling towers and railroad. The piping replacement effort was concentrated in these areas first. As the failure rate of the remaining areas was relatively low, completing the rest of the work scope was delayed to allow the funds to be used to address other piping systems (fire water, service water, bearing cooling water) that were experiencing increasingly higher failure rates. As these other piping systems became critical, the allocated funds were directed at these systems or the budgeted funds were used to offset other plant expenses. In the last couple of years, the pipeline failure rates in the remaining areas have started to increase and these areas now have a higher priority to be replaced. The first 13 zones were mainly underground piping systems. The bulk of the remaining replacement will be above ground, which requires heat tracing, insulation, and lagging. In 2010, the project will focus on above ground piping systems that include the air preheater discharge headers, firewater, oily water, and service water.	$ 158,272	$ 50,113	$ 208,385	6/30/2011
122.	WPC0204	West Phoenix CC 1	Prevent Failure	BFP Recirculation Piping Redesign	The purpose of this project is to redesign the Unit 1 boiler feed pump recirculation system to eliminate cavitation within the pump thereby reducing pump failure and maintaining unit reliability.	$ 2,775	$ 205,528	$ 208,303	3/19/2011
123.	RHC0118	Redhawk Units 1 & 2	Prevent Failure	Cooling Tower XFMR Bus Protection	The purpose of this project is to protect the transformers and bus ducts from damage due to the ambient environment and cooling tower drift. During a recent storm, the bus duct was exposed to rain and faulted. Water intrusion was also found in the transformers. The new structure will provide protection from the weather and cooling tower drift that is deteriorating the transformers and bus duct.	$ 139,754	$ 66,400	$ 206,154	1/31/2011
124.	CHC0345	Cholla Unit 2	Reliability	Cable Tray & Cable Replacement, Phase 6A	Several of the cables installed underground have failed. This is a proactive attempt to replace cables before they cause a forced outage or load reduction, as well as to replace failed cables which have been repaired or replaced on a temporary basis. Cables are being replaced in overhead raceway to avoid the effects of submersed cables in manholes, conduits which have been damaged or deteriorated, and the safety difficulties of replacing cables in manholes with other energized circuits present. Specific pmps include Demister Water, Scrubber Recycle, and also includes Diesel Gen Swgr and Unit 2 MCC.	$ -	$ 204,627	$ 204,627	6/24/2011
125.	SDC0044	Sundance Common	Reliability	Auxiliary Power Transfer	The purpose of this project is to be able to maintain plant common auxiliary power during an outage on a power block. Present condition is that if the power block supplying the BOP auxiliary power has to be de-energized, the BOP system has to be shut down to transfer source of power to the second power block. During the transfer, power to common facilities is lost. The modification will allow power to common facilities to remain on.	$ -	$ 204,313	$ 204,313	11/10/2011
126.	YUC0073	Yucca GT Units 5 & 6	Reliability	Chiller Bypass	The purpose of this project is to install a bypass around chiller 200A&B condenser and evaporators. This will allow isolation for either of the chiller.	$ -	$ 193,376	$ 193,376	3/9/2012
127.	FBC90168	Four Corners Units 4 & 5	Reliability	U45 Absorber Module Blowdown Upgde	The components of the existing absorber module blow down system are worn out and cannot support the higher SO2 removal rates. As a result, waste slurry sump overflows, chloride excursions, and grit build up in the absorber modules are becoming frequent and are adversely affecting the scrubbing process increasing O&M cost. Project will result in reduced lime usage, maintained thickener performance/reliability, and enhanced TUT flow to the ash ponds.	$ 164,510	$ 23,738	$ 188,249	3/25/2011

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
128.	60-0913	Navajo Units 1, 2, 3	Reliability	Service Building Refurbishment	Refurbish the west side of the Service Building. This refurbishment will include replacing the plumbing and HVAC systems, reconfiguring the restroom and shower facilities to match the gender of the current workforce and installing a room for large measure.	$ 184,355	$ 1,422	$ 185,776	1/31/2011
129.	FBC90390	Four Corners Units 4 & 5	Prevent Failure	Aux Transformer Spare	Auxiliary transformers are required to be able to operate Units 4 and 5 simultaneously. If an aux transformer is not available and that unit is operating on the reserve bus, the unit would have to be curtailed to be able to start up the other unit. If the unit with an auxiliary transformer were to trip, the reserve bus would have to carry both units' auxiliaries and would overload until the units' aux loads could be reduced.	$ -	$ 184,438	$ 184,438	11/12/2011
130.	60-1086	Navajo Unit 2	Reliability	Precipitator Deck Replacement-2	The precipitator deck is a composite of concrete on top of corrugated steel that serves as the tension component of the deck. Cracks in the concrete have allowed moisture to seep in and corrode the corrugated steel. The load-carrying capacity of the deck has thus been reduced and may pose a risk of failure with the use of heavy equipment. The Unit 1 lower deck (the deck in the worst condition) was replaced in 2008 and the Unit 3 lower deck is scheduled for 2009. In 2010, the Unit 2 lower deck will be replaced.	$ 175,761	$ 8,133	$ 183,893	6/30/2011
131.	60-1163	Navajo Units 1, 2, 3	Reliability	Circuit Breakers, Switchgear Repairs	NGS will replace the operating mechanism on the 4160V scrubber breakers. The scrubber type 5-VHK-2S0, model 20, ASS vacuum 4160V breakers have become a safety issue. Operating mechanism failures have resulted in arcing when Operations racks in these breakers. NGS will purchase two new breakers to allow cycling of the 40 scrubber breakers for repair. The spare breakers remaining after the repairs will be used for cycling breakers during future preventive maintenance cycles. The plan is to replace the operating mechanism every 10 years, with a 5 year PM cycle.	$ -	$ 177,385	$ 177,385	12/31/2011
132.	60-0811	Navajo Units 1, 2, 3	Reliability	Intelligent Sootblowing Breakout	Some areas of the Navajo boilers have soot blown too much, while other areas don't have it blown enough. Blowing too much erodes boiler tubes, and erosion is a major cause of tube failures, which results in Unit forced outages.	$ 157,155	$ 14,588	$ 171,743	4/3/2011
133.	OCC0071	Ocotillo Common	Reliability	Security, CCTV Replacement	The purpose of this project is to improve plant and personnel security and safety.	$ 21,397	$ 142,557	$ 163,954	4/1/2011
134.	WPC0186	West Phoenix CC 5	Reliability	Boiler Feedwater Recirc Valve Replacement	Existing system design is not robust enough to handle cyclic unit operation. As a result the recirculation control valves must be rebuilt every year or two.	$ -	$ 163,913	$ 163,913	3/23/2012
135.	WPC0156	West Phoenix CC 1	Prevent Failure	CC1 Battery Replacement	These are required to support unit functions during loss of AC power.	$ 125,586	$ 34,264	$ 159,851	3/19/2011
136.	SDC0026	Sundance Common	Safety / Security	Lightning Prot & Grounding	The purpose of the project is to identify if a lower the ground resistance and associated arrestors are needed at the plant to make it safer during lightning storms and system faults. Then to make the changes as determined.	$ -	$ 159,390	$ 159,390	6/25/2011
137.	RHC0099	Redhawk Common	Prevent Failure	RO Membrane Replacement	The purpose of this project is to purchase replacement first pass RO membranes to ensure continued production of high purity water.	$ 151,990	$ 7,033	$ 159,023	6/30/2011
138.	FBC90080	Four Corners Units 4 & 5	Reliability	U4-5 Reserve Transf Breaker Addition	Install new breakers and associated equipment to individually isolate the Reserve Auxiliary Transformers.	$ 64,130	$ 94,097	$ 158,227	11/30/2011
139.	WPC0134	West Phoenix CC 4	Safety / Security	Cooling Tower Fan Deck Replacement	The existing treated plywood deck is showing signs of deterioration and will need to be replaced to ensure structural integrity of the tower support diaphragm (fan deck) and provide a safe walking surface for plant personnel.	$ -	$ 156,941	$ 156,941	12/16/2011

Fossil Post-Test Year Plant Additions

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
140.	WPC0208	West Phoenix CC 1, 2, 3	Safety / Security	Cooling Twr Sodium Hypochlor Add Sys	The purpose of this project is to replace the existing Cooling Tower Sodium Hypochloride Injection Skids (pumps, instrumentation, and piping) with a gravity feed system. The existing system is prone to leaks and the pumps are prone to failure due to the nature of the material being pumped. Safety concern manually feeding chemicals because of weight of portable containers and excessive exposure to chemicals.	$ -	$ 156,362	$ 156,362	11/30/2011
141.	WPC0210	West Phoenix CC 5	Safety / Security	Cooling Twr Sodium Hypochlor Add Sys	The purpose of this project is to replace the existing Cooling Tower Sodium Hypochloride Injection Skids (pumps, instrumentation, and piping) with a gravity feed system. The existing system is prone to leaks and the pumps are prone to failure due to the nature of the material being pumped. Safety concern manually feeding chemicals because of weight of portable containers and excessive exposure to chemicals.	$ -	$ 156,362	$ 156,362	11/30/2011
142.	YUC0075	Yucca Common	Reliability	Gas Storage Shelter (APS Share)	Currently the plant has limited gas storage.	$ 195,900	$ (40,651)	$ 155,249	1/31/2011
143.	WPC0183	West Phoenix CC 4	Reliability	Cooling Tower Drift Eliminators Replacement	Maintain environmental compliance with Plant air operating permit.	$ -	$ 151,709	$ 151,709	12/15/2011
144.	CHC0323	Cholla Unit 3	Prevent Failure	Station Battery Charger Replacement	The purpose of this project is to maintain reliable source to charge unit batteries for the 125VDC distribution system. The battery chargers are plant original equipment (1981).	$ 15,147	$ 135,570	$ 150,717	4/1/2011
145.	CHC0334	Cholla Common	Reliability	Tools & Equipment - 2011	Misc cap tool for projects including DC ground Fault Trouble shooting meter, Robot Control welder, Tube cutting/Prep mill tool, and Tube bending dies.	$ -	$ 149,109	$ 149,109	12/15/2011
146.	60-1170	Navajo Units 1, 2, 3	Reliability	Control System Replacement	Replace obsolete control systems as existing systems become unrepairable due to lack of availability of replacement parts. NGS maintains the existing DCS and PLC systems as components age from "Maturity" status to "Lifetime" status. "Maturity begins when the product is withdrawn from sales. "Lifetime" reflects the period when there is no guarantee the item can be supported; components are provided and maintained as long as parts are available, but they are no longer in production. The UNIX work stations are obsolete, and the Solaris operating system that is used on all three units' work stations is no longer supported as of January 2010. These systems will be replaced, starting with Unit 1 in 2011, using Windows-based work stations, control system peripherals, and the ItA Series System from Foxboro.	$ -	$ 146,038	$ 146,038	12/31/2011
147.	CHC0222	Cholla Unit 2	Reliability	U2 Scrubber Elev Controls Replacement	Make the Scrubber Elevator more reliable and avoid delays in productivity or module return to service. Controls are to be replaced in compliance with ASME/ANSI A17.1 and 17.3, which require replacement rather than modification with non-OEM parts.	$ 16,604	$ 129,403	$ 146,007	1/1/2012

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
148.	60-1173	Navajo Units 1, 2, 3	Reliability	DCS Field Devices	Improvements to field devices around the plant are necessary to optimize the control systems' capabilities for improved load following, run backs, and all systems controls. These improvements will allow the devices to be integrated with the control system. The following equipment will be addressed in 2011: 1) Feedwater Header Level Controls do not meet ASME recommendations for water induction prevention. The manufacturer of the current system, Masoneilan, discontinued sales of parts effective February of 2009. NGS's current Masoneilan level controllers use antiquated pneumatic technology. Related control valves are imprecise and heater levels fluctuate widely. Current conditions contribute to leaks and shell erosion. The project to replace the current Feedwater heater level controls with a DCS compatible Clark-Reliance/Jerguson control package will be completed in 2011. 2) The boiler Acoustic Leak Detection System (ALDS) is obsolete and no longer supported by the manufacturer. Parts are limited to stock on hand. A retrofit is available at a substantial savings vs. a complete replacement. NGS will replace the CE/Lintv"alve T6 ALDS with a LA 202 ALDS system on Unit 1 during the overhaul. 3) New REXA actuators will be installed on the Unit 1 SP and WD Valves to replace the CopesNulcan actuator and positioner that are failing due to the extreme heat in their location. 4) Obsolete and unsupported coal silo level devices will be replaced. Manufacturer parts are no longer available and NGS has depleted the spare parts inventory for the current devices. 5) The existing Stator Cooling System temperature, pressure and flow alarm devices are antiquated, inaccurate and difficult to replace. NGS will complete the replacement of redundant mercroid switches and thermo-bulb switches with existing Siemens' transmitters and 3-element J-type thermocouples on Unit 1 in 2011.	$ -	$ 145,745	$ 145,745	12/31/2011
149.	60-1060	Navajo Units 1, 2, 3	Environmental Compliance	Cathodic Protection Wells Replacement-Com	Inspection of the 56 existing cathodic protection wells found that only 13 were operational with no immediate maintenance needs. The Cathodic Protection Wells protect the underground piping system from corrosion. These wells are original plant equipment and have been collapsing.	$ 12,546	$ 130,983	$ 143,529	6/30/2011
150.	CHC0303	Cholla Common	Reliability	Coal Handling Bldgs Roof Replacement	The purpose of this project is to replace the 28 year old leaking coal handling building roofs in order to protect control system and switchgear investments and the operation of the Cholla coal handling system. The condition of the roofs have deteriorated to the point that replacement is the practical solution. Replacement is recommended to protect the control room and switchgear equipment.	$ 15,068	$ 125,864	$ 140,932	6/1/2011
151.	SAC0062	Saguaro Common	Reliability	Remote Start, CT 1-3 From Sundance	To enable remote control of all three Saguaro Combustion Turbines from Sundance.	$ 122,145	$ 17,335	$ 139,480	6/30/2011
152.	FCC90396	Four Corners Common	Environmental Compliance	Off-Site Resin Regeneration	The purpose of this project is to eliminate on-site resin regeneration. The resin regeneration equipment in the Common "150-gpm" demineralizer system is to be demolished and replaced with a header designed to receive vendor supplied resin tanks. The vendor tanks are to be filled with resin that is regenerated at their facilities.	$ -	$ 138,754	$ 138,754	12/23/2011
153.	WPC0158	West Phoenix CC 3	Prevent Failure	CC3 Battery Replacement	These are required to support unit functions during loss of AC power.	$ 96,636	$ 32,428	$ 129,064	4/15/2011
154.	60-1019	Navajo Units 1, 2, 3	Reliability	Pulverizer Dynamic Analysis System	NGS recommends installation of a Dynamoc Analysis System on each (21) pulverizer, which would provide real-time predictive maintenance data on machines.	$ 124,538	$ 3,842	$ 128,380	4/30/2011

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
155.	60-1073	Navajo Units 1, 2, 3	Reliability	DCS Field Devices-Com	Improvements to field devices around the plant are necessary to optimize the control systems' capabilities for improved load following, run backs, and all systems controls. These improvements will allow the devices to be integrated with the control system. The following equipment will be addressed in 2010 - 2011. 1) Feedwater Header Level Controls do not meet ASME recommendations for water induction prevention. The manufacturer of the current system, Masoneilan, discontinued sales of parts effective February of 2009. NGS's current Masoneilan level controllers use antiquated pneumatic technology. Related control valves are imprecise and heater levels fluctuate widely. Current conditions contribute to leaks and shell erosion. Feedwater heater level controls will be replaced with a DCS compatible Clark-Reliance/Jerguson control package. 2) The boiler Acoustic Leak Detection System (ALDS) is obsolete and no longer supported by the manufacturer. Parts are limited to stock on hand. A retrofit is available at a substantial savings vs. a complete replacement. NGS will replace the CE/Lintvalve T6 ALDS with a LA 202 ALDS system. This retrofit will allow NGS to utilize existing field wiring and relay room cabinetry. 3) The existing Stator Cooling System temperature, pressure and flow alarm devices are antiquated, inaccurate and difficult to replace. Replacement of redundant mercroid switches and thermo-bulb switches with existing Siemens' transmitters and 3-element J-type thermocouples will increase accuracy and provide DCS compatibility.	$ 120,084	$ 7,517	$ 127,601	6/30/2011
156.	SAC0066	Saguaro Common	Safety / Security	Cathodic Protection Sys #1, 3, 4 Replacement	Cathodic Protection provides protection against corrosion for all underground pipes at the Plant. The systems that must be replaced protect the oil tanks and natural gas lines at the Plant.	$ -	$ 125,552	$ 125,552	12/2/2011
157.	WPC0182	West Phoenix CC 4	Reliability	Cooling Tower Fan Purchase	The purpose of this project is to replace the cooling tower fans to ensure safe, reliable operation. Cooling tower fan hubs are corroding as a result of failed coatings.	$ -	$ 124,627	$ 124,627	10/7/2011
158.	60-1004C	Navajo Units 1, 2, 3	Reliability	Computer and Network Infrastructure	This project will replace personal computers (PC's) certain monitors, and various peripheral devices. NGS's desktop PC's are currently four years old. They are beginning to fail and their warranties have expired. PC monitors that are replaced will be used as terminal monitors, with the remainder kept as spares. Peripheral devices will be evaluated and replaced as required.	$ 64,345	$ 58,336	$ 122,681	4/30/2011
159.	YUC0051	Yucca GT Units 1 & 2	Prevent Failure	Auto Sync Relay Replacement	The purpose of this project is to restore the synchronizing protection to the combustion turbines. The electromechanical relays (2 relays on each of the two units at Yucca) require periodic calibration and repairs and provide protective functions to properly synchronize the units to the system. The original relays and parts are no longer available from the original manufacturer.	$ 42,685	$ 77,321	$ 120,006	1/15/2011
160.	WPC0172	West Phoenix CC 4	Reliability	Steam Turbine Coupling	The fasteners and spacer on the steam turbine coupling were replaced in 2005 after the coupling was exposed to a high load condition which caused it to fail. The reliability and performance of the coupling are uncertain and there is not a spare coupling on site. The lead time for a new coupling is 26 weeks.	$ 416	$ 114,756	$ 115,171	4/29/2011
161.	WPC0203	West Phoenix CC 5	Reliability	Distillate Tank Replacement	The purpose of this project is to replace ZLD Distillate Tank and piping to ensure operation of ZLD. The ZLD is required for operating CC5A, CC5B, CC5ST. Continued operation of ZLD under current conditions creates an unsafe work environment due to spraying hot water.	$ -	$ 115,090	$ 115,090	12/5/2011
162.	WPC06114	West Phoenix CC 4	Reliability	Cooling Twr Mech Equip Access Walkways	Allow safe access to fan assemblies mechanical equipment.	$ -	$ 111,697	$ 111,697	4/20/2012

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
163.	60-1181	Navajo Units 1, 2, 3	Reliability	Prot Relay Replacement	These devices ensure the protection and integrity of plant equipment and sub-systems vital to equipment availability. These devices will be replaced with more advanced digital technology for more reliable, quicker information after high current faults. This information will be used to insure proper protection and preventive maintenance of valuable equipment and systems. In 2011, NGS will focus on relay protection work on Unit 1 auxiliary equipment including; Induced Draft Fans, Primary Draft Fans, Circulating Water Pumps, Boiler Circulating Water Pumps and Unit Auxiliary Transformers. The protective relay modernization is designed to update antiquated relay hardware, which will positively impact long term maintenance and failure risk.	$ -	$ 111,616	$ 111,616	12/31/2011
164.	WPC0157	West Phoenix CC 2	Prevent Failure	CC2 Battery Replacement	These are required to support unit functions during loss of AC power.	$ 92,509	$ 18,600	$ 111,110	3/25/2011
165.	FBC90378	Four Corners Unit 5	Safety / Security	Arc Flash Mitigation	The purpose of this project is to comply with NFPA 70E and Fossil Generation Managerial Policy S-15.	$ 1,814	$ 107,699	$ 109,514	5/1/2011
166.	FBC90172	Four Corners Units 4 & 5	Reliability	U45 Undergrnd Cooling Water Systems	The East flush water pump is currently leaking where the piping is above ground. Some of this piping has already had multiple repairs to it. Failure of any of these piping components will subject the auxiliary bay of Units 4&5 to flooding. In addition, a unit outage of 5 days will be required to repair this piping.	$ 78,792	$ 29,794	$ 108,586	5/2/2011
167.	OCC0065	Ocotillo Stm Units 1 & 2	Reliability	Boiler Maint Tracking Software	The purpose of this project is to maintain the frequency and length of boiler tube leak outages by maintaining good condition assessment and repair information on the boilers.	$ 91,089	$ 14,693	$ 105,782	6/30/2011
168.	WPC0159	West Phoenix GT 1	Prevent Failure	GT1 Battery Replacement	These are required to support unit functions during loss of AC power.	$ 99,229	$ 6,431	$ 105,660	1/27/2011
169.	OCC0083	Ocotillo Stm Units 1 & 2	Environmental Compliance	CEMS Upgrade	The current CEMS is antiquated and is causing low monitor availability. This project upgrades the system to state-of-the-art technology and should maintain the system availability.	$ -	$ 104,241	$ 104,241	11/18/2011
170.	FBC90336	Four Corners Unit 5	Reliability	TSI Replacement	The purpose of this project is to replace the existing Turbine / Generator (T/G) supervisory instrumentation system (TSI) with a new vibration and critical monitoring system. The project will also integrate the new TSI system analog, alarm, and trip signals into the plant-wide Distributed Control System (DCS) and data historian.	$ 48,026	$ 55,097	$ 103,123	4/22/2011
171.	60-1070	Navajo Units 1, 2, 3	Reliability	Control System Replacement-Com	Replace obsolete control systems as existing systems become unrepairable due to lack of availability of replacement parts. Maintain the existing DCS and PLC systems as components age from "Maturity" status to "Lifetime" status. "Maturity begins when the product is withdrawn from sales. "Lifetime" reflects the period when there is no guarantee the item can be supported; components are provided and maintained as long as parts are available, but they are no longer in production. The following equipment will be addressed. 1) The Servo positioners for both the Auxiliary and Main Turbines will be replaced. Current equipment is obsolete ant there are no compatible substitutes. Parts are limited to current onsite spares. Replacement will require a change to the turbine control system. 2) The COMM30 communication modules are no longer available from Foxboro. There are 26 modules on site that need to be replaced with current Foxboro equipment. 3) Unit 1 UNIX work stations are obsolete and the Solaris operating system that is used on all three units' work stations will no longer be supported after January 2010. These systems will be replaced with Windows based work stations from Foxboro.	$ 15,994	$ 86,505	$ 102,499	6/30/2011
172.	WPC0193	West Phoenix Common	Prevent Failure	Cathodic Protection Replacement	Cathodic Protection of the natural gas and diesel pipelines is regulatory requirement audited by the ACC.	$ -	$ 101,928	$ 101,928	5/31/2011

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
173.	RHC0124	Redhawk Unit 1	Reliability	HRSG Feedwater Pump Motor Replacement	The purpose of this project is to replace the motor to reduce/eliminate vibration concers and provide reliable future operation of the Unit. The existing motor is experiencing abnormally high vibrations and poses a risk to generation.	$ 96,826	$ 4,480	$ 101,306	6/30/2011
174.	60-0711	Navajo Units 1, 2, 3	Reliability	HVAC Air handler Replacement/Aux Bldgs	Major components of these air handling components (such as motors, cooling/heating coils, and fans) are beginning to fail, and direct replacements for these components are no longer available. Current fire protection requirements call for fire dampers an fan controls that are not easily added to the existing units. SRP has determined that the most cost effective long-term solution for maintaining reliable temperature controls for personnel and critical electrical components, and for providing an up-to-date level of fire protection, is replacement of these ten air handling units.	$ 50,291	$ 44,165	$ 94,457	12/31/2011
175.	OCC0080	Ocotillo Common	Reliability	Tools - 2011	Misc cap tool for projects including IR Camera.	$ -	$ 94,164	$ 94,164	12/15/2011
176.	OCC0068	Ocotillo Common	Reliability	Video Conf Equip Install	Project is to enhance the Generation Videoconferencing system providing continuity of use, additional capability & connectivity, and provide upgrades to older systems which not only allow additional function.	$ 87,917	$ 4,068	$ 91,985	6/30/2011
177.	SDC06353	Sundance Units 1-10	Reliability	CEMS UPS Power Supply	The purpose of this project is to power critical CEMS equipment from the PECC UPS System to allow for controlled shutdown of the CEMS equipment. The original CEMS System is equipped with a standalone, rack mount UPS/Battery system which needs to be replaced due to faulty batteries.	$ -	$ 86,966	$ 86,966	6/11/2012
178.	60-1081	Navajo Units 1, 2, 3	Reliability	Protection Relay Replacement-Com	These devices ensure the protection and integrity of plant equipment and sub-systems vital to equipment availability. These devices will be replaced with more advanced digital technology for more reliable, quicker information after high current faults. This information will be used to insure proper protection and preventive maintenance of valuable equipment and systems. In 2010, NGS will focus on relay protection work on Unit 2 auxiliary equipment including; Induced Draft Fans, Primary Draft Fans, Circ Water Pumps, Boiler Circulating Water Pumps and Unit Auxiliary Transformers. The protective relay modernization is designed to update antiquated relay hardware, which will positively impact long term maintenance and failure risk.	$ 81,598	$ 5,048	$ 86,646	6/30/2011
179.	FCC90363	Four Corners Common	Environmental Compliance	Vacuumed Dust Disposal Upgrade	The purpose of this project is to control fugitive dust generated when vacuum trucks dump fly ash and other collected materials at the Dry Fly Ash Disposal Site. Spraying or foaming equipment will minimize the dust generated during the dumping operation.	$ 14,328	$ 69,991	$ 84,319	2/18/2011
180.	WPC0184	West Phoenix CC 4	Reliability	HP Drum Fill Valve	The existing HP drum level control valve is not designed for the high differential pressure associated with filling the unit or making up to the drum under cold conditions. The valve internals are damaged quickly under these operating conditions.	$ -	$ 81,865	$ 81,865	4/20/2012
181.	WPC0075	West Phoenix CC 1, 2, 3	Prevent Failure	Zurn Coupling	The purpose of this project is to purchase a spare Zurn coupling to replace the warehouse spare that was recently installed in CC1. The Zurn coupling has a life expectancy of five years based on historical maintenance. Lead time on a replacement coupling is 26 - 28 weeks. For these reasons a spare coupling is necessary.	$ -	$ 80,934	$ 80,934	2/28/2011
182.	FBC90370	Four Corners Unit 5	Reliability	Reheat Isolation Valves	The purpose of this project is to isolate the reheat section of the boiler during hydrostatic testing, allowing leaks to be located quickly and thereby reducing unit start-up time after overhaul.	$ 17,596	$ 63,070	$ 80,666	4/24/2011

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
183.	NPA00558	Navajo Units 1, 2, 3	Safety / Security	Plant Wide Emerg Evac Notification System	Install a plant-wide emergency notification system that works in conjunction with the existing fire alarm panels. Notification will ne accomplished in general use areas of the plant with a multi0pattern sirent, and in high noise areas with horns and strobes.	$ -	$ 79,245	$ 79,245	12/31/2011
184.	SAC0067	Saguaro Common	Reliability	Remote HMIs for Saguaro at Sundance	To allow the Sundance Control operators to have more control capabilities over the Saguaro units. This also gives them access to all of the operating information for the units.	$ -	$ 78,181	$ 78,181	11/18/2011
185.	WPC0209	West Phoenix CC 4	Safety / Security	Cooling Twr Sodium Hypochlor Add Sys	The purpose of this project is to replace the existing Cooling Tower Sodium Hypochloride Injection Skids (pumps, instrumentation, and piping) with a gravity feed system. The existing system is prone to leaks and the pumps are prone to failure due to the nature of the material being pumped. Safety concern manually feeding chemicals because of weight of portable containers and excessive exposure to chemicals.	$ -	$ 78,181	$ 78,181	11/30/2011
186.	RHC0126	Redhawk Common	Safety / Security	Chemical Feed System	To improve safety with handling chemicals.	$ 12,996	$ 64,892	$ 77,889	4/1/2011
187.	CHC0315	Cholla Common	Safety / Security	Lockout-Tagout System	Install the Lockout-Tagout (LOTO) system including software, four (4) PC stations, five (5) large printers, lock boxes and lock box accessories.	$ 73,974	$ 3,423	$ 77,397	6/30/2011
188.	FBC90388	Four Corners Unit 4	Reliability	Aux Steam Flow Control Valve Replacement	The purpose of this project is to ensure dependability of the Unit 4 auxiliary steam high demand flow control for Unit 4 normal full-load operation and Unit 5 start-up and shutdown auxiliary steam demand. The Unit 4 control valve and actuator have failed, preventing the valve from fully closing.	$ -	$ 74,932	$ 74,932	10/27/2011
189.	WPC0173	West Phoenix CC 1, 2, 3	Prevent Failure	4160V Breaker Reassignment	Facilitate safe maintenance practices without requiring complete shutdown of both power sources to switchgear.	$ 19,513	$ 54,065	$ 73,578	3/18/2011
190.	FBC90389	Four Corners Unit 5	Reliability	Aux Steam Flow Control Valve Replacement	The purpose of this project is to ensure dependability of the Unit 5 auxiliary steam high demand flow control for Unit 5 normal full-load operation and Unit 4 start-up and shutdown auxiliary steam demand. The Unit 4 control valve and actuator have failed, preventing the valve from fully closing. Currently Unit 4 auxiliary steam demand is being met by Unit 5 for start-up and shutdown purposes.	$ -	$ 73,541	$ 73,541	5/21/2011
191.	NPA00557	Navajo Common	Reliability	Exciter Breaker Replacement	The field breaker that protects the generator excitation system for NGS's unique exciter design is neither reliable nor repairable. Have a more robust breaker designed and install one on each unit.	$ -	$ 72,277	$ 72,277	12/31/2011
192.	60-1080	Navajo Units 1, 2, 3	Environmental Compliance	Coal Yard Dust Collector Sys-Com	The current dust collection system at NGS is outdated and many parts are obsolete. Maintaining this system is very time consuming and the results of this system's poor performance are creating safety and housekeeping issues throughout the coal handling areas. Combustible dust has become a priority following incidents in other facilities.	$ 67,279	$ 3,113	$ 70,392	6/30/2011
193.	FCC90398	Four Corners Common	Reliability	Tools, New and Replacement, 2011	Replacement and tools used for projects. Examples include a high speed handheld beveller, beveller for prepping pipe to 8-3/4", and a flange de-facing tool.	$ -	$ 70,383	$ 70,383	12/15/2011
194.	60-1010C	Navajo Units 1, 2, 3	Reliability	Dissolved Gas Anlyzr MSS-RS-Main Tr	Replace the existing dissolved gas analyzers on the main auxiliary transformers (3) and the Maub Station Service transformers with Severon True Gas TM-8 monitors.	$ 39,301	$ 28,391	$ 67,692	12/31/2011

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
195.	WPC0174	West Phoenix Common	Safety / Security	Lockout-Tagout System	This project is required to standardize fleet production of lockout-tagout tags, and will reduce the risk of safety events due to human performance error. The Company has benchmarked other companies' best practices resulting in a complete re-write of the lockout-tagout process and procedure. This WA funds the purchase of software and equipment necessary to implement the new best practices for the lockout-tagout process and procedure.	$ 62,674	$ 2,900	$ 65,574	6/30/2011
196.	60-1077	Navajo Units 1, 2, 3	Reliability	Facilities Maint-Roof Repairs-Com	Evaluation of the plant's roofing, floors and walls shows deterioration that requires repairs or replacement. NGS will make the following facilities repairs in 2010-2011: 1) Replace Water Treatment Building and Chlorine Building roof. Engineering inspections over the past several years found the water treatment building and Chlorine Building roofs to be in poor condition. The roofs on these buildings are original plant construction. Roof replacement will ensure these buildings will continue to provide shelter and protection to vital operations in this area of the plant. 2) Replace power block underground sanitary service and underground floor drain piping. NGS regularly experiences underground drain/sewer line plugs in the power block. In the past two years, each unit has required extensive contractor work to unplug drain lines. Recently, Unit experienced a sewer drain pipe failure that will require immediate repair. Based on inspection, NGS believes that the balance of the underground sewer piping in the power block area is at the end of its service life and requires replacement.	$ 29,805	$ 33,295	$ 63,101	6/30/2011
197.	60-1005C	Navajo Units 1, 2, 3	Reliability	Plant Historian Replacement	NGS's current plant historian is no longer reliable, is limited in functionality compared to what is available today, and will soon be out of sync with the rest of SRP. Lack of reliability was a major issue during the start-up and tuning of the low NOx burners on Unit 3. NGS recommends the purchase and installation of OSI PI software and its corresponding hardware.	$ 59,315	$ 1,372	$ 60,687	3/31/2011
198.	FCC90380	Four Corners Common	Environmental Compliance	Ash Pond Seepage Intercept	To intercept ash pond seepage.	$ 952	$ 57,217	$ 58,169	6/1/2011
199.	FBC90335	Four Corners Unit 5	Reliability	Turbine HPU Heat Exchanger Replacement	The purpose of this project is to eliminate the possibility of water contamination of the turbine hydraulic oil system, thereby mitigating the risk of a forced outage, and to provide additional flow in the event one of the Air/Oil Heat Exchangers or one of the Kidney Pumps has to be taken out of service.	$ 16,093	$ 37,733	$ 53,827	4/22/2011
200.	YUC0063	Yucca Common	Reliability	Tools - 2011	Tools used for projects. Examples include vibration meter, megohm meter, thermocouple calibrator, mechanical shears, and track cutting machine.	$ -	$ 52,314	$ 52,314	12/15/2011
201.	SDC0045	Sundance Common	Reliability	Remote HMIs for Saguaro at Sundance	Misc cap tool for projects including instrument test bench.	$ -	$ 52,314	$ 52,314	12/15/2011
202.	60-1026	Navajo Units 1, 2, 3	Reliability	Performance Monitor Replacement	NGS's current performance monitor is obsolete and non-functional. Purchase a new performance monitor.	$ 50,419	$ 1,555	$ 51,974	4/30/2011
203.	WPC0170	West Phoenix CC 1, 2, 3	Prevent Failure	480V Power Center Breaker Replacement	This switchgear provides power to the fuel oil unloading area. Without this MCC oil storage and customer load are out of service. The existing breakers are non-operational and the manufacturer no longer supports the replacement parts, so breakers with current technology will be installed as is being done throughout the fleet with breakers of this vintage.	$ 21,431	$ 30,004	$ 51,434	6/30/2011
204.	OCC0079	Ocotillo Common	Prevent Failure	Cathodic Protection	The cathodic protection of our natural gas pipelines is a regulatory and safety requirement. CPS #1 being operational is required to protect the necessary cathodic protection.	$ -	$ 51,350	$ 51,350	7/15/2011

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
205.	FBC90392	Four Corners Unit 5	Reliability	Furnace Temperature Monitor	The purpose of this project is to maintain unit reliability by preventing superheat and reheat tube damage due to high startup flue gas temperatures. Damage occurs from overheating of the tubes which causes cracks and leaks. The new system will monitor the flue gas temperatures during startup.	$ -	$ 49,843	$ 49,843	5/21/2011
206.	RHC0117	Redhawk Units 1 & 2	Reliability	Isophase Duct Protection	The purpose is to prevent rain water from entering the generator enclosure where the isophase ducts penetrate the roof. Due to the configuration of the ducts and location of the roof penetration, sealing the area against rain is difficult.	$ 47,238	$ 2,186	$ 49,423	6/30/2011
207.	RHC0137	Redhawk Common	Safety / Security	Lockout-Tagout System	This project is required to standardize fleet production of lockout-tagout tags, and will reduce the risk of safety events due to human performance error. The Company has benchmarked other companies' best practices resulting in a complete re-write of the lockout-tagout process and procedure. This WA funds the purchase of software and equipment necessary to implement the new best practices for the lockout-tagout process and procedure.	$ 46,869	$ 2,169	$ 49,037	6/30/2011
208.	60-1015C	Navajo Units 1, 2, 3	Reliability	Op Emg-Cap Exp-Spare Parts Continge	This budget item is to cover capital expenditures to comply with sections 15.2 and 17.1 of the Navajo Generating Station Operating Agreement. Examples of past expenditures from this line item include the purchase of an audiometer and a generator step-up transformer dissolved gas analyzer, and installing a ventilation system for the tool room.	$ 47,318	$ 730	$ 48,048	2/28/2011
209.	FBC90391	Four Corners Units 4 & 5	Environmental Compliance	Off-Site Resin Regeneration	The purpose of this project is to eliminate on-site resin regeneration. The resin regeneration equipment in the Unit 4 & 5 "in-line" demineralizer system is to be demolished and replaced with a header designed to receive vendor supplied resin tanks. The vendor tanks are to be filled with resin that is regenerated at their facilities.	$ -	$ 47,867	$ 47,867	12/23/2011
210.	60-0915	Navajo Units 1, 2, 3	Reliability	Op Emgncy-Cap Exp-Spare Parts	Capital expenditures to comply with sections 15.2 and 17.1 of the Navajo Generating Station Operating Agreement. Examples of past expenditures from this line item include the purchase of an audiometer and a generator step-up transformer dissolved gas analyzer, and installing a ventilation system for the tool room.	$ 44,296	$ 2,050	$ 46,345	6/30/2011
211.	60-1165	Navajo Unit 2	Environmental Compliance	Main Turbine TSI Diagnostic-2	The Main Turbines and Auxiliary Turbines were originally provided with vibration probes (Shaft Riders) that provided vibration indications to the operators and engineers, balance data, and a method to take local readings with a portable device for balancing and diagnostics. The Shaft Rider vibration probes are now obsolete and replacements for the original probes cannot be purchased. In addition to replacing the probes, it will be necessary to replace the signal conditioning electronics (which are also original equipment) with updated equipment, compatible with the new probes. The Shaft Riders provide data that is complementary to the proximity probes on the Main Turbine, and are the only vibration indications for the Auxiliary Turbines. The majority of the historic balance data is from using the Shaft Riders and portable instruments. The Shaft Riders along with a portable device also allow measurement and comparison of bearing and coupling vibrations. In the past, balancing of the coupling was necessary and was difficult without the Shaft Rider comparison. NGS will replace the main turbine shaft riders during the 2011 major overhaul.	$ 22,094	$ 22,574	$ 44,668	4/3/2011
212.	60-0925	Navajo Units 1, 2, 3	Environmental Compliance	Bottom Ash Level Monitoring System	The purpose of this project is to improve operation of the bottom ash system by adding fixed sonar ash level monitoring systems to the bottom ash hoppers to complement the nuclear ash density meters on the ash conveying pipe by showing if the hopper is empty or bridged when the density meter detects no ash.	$ 37,717	$ 5,756	$ 43,473	4/3/2011
213.	CHC0178	Cholla Common	Reliability	CP Rectifier Remote Monitoring Delayed	Sustain the company's corrosion control program to preserve assets, reduce maintenance costs, comply with government regulations, and preserve the environment.	$ -	$ 41,206	$ 41,206	1/1/2012

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
214.	FBC90407	Four Corners Units 4 & 5	Reliability	4N PA Fan Replacement	The purpose of this project is to maintain unit availability.	$ -	$ 38,734	$ 38,734	1/11/2012
215.	60-1063	Navajo Units 1, 2, 3	Reliability	Circuit Breaker-Switchgear Rep-Com	The 480V Air Interrupt Open Frame (AK) breakers in the GE Air Interrupt Open Frame Drawout (AKD) switchgear are original plant equipment. These breakers are used as contactors, and have accumulated a large number of operations. They are both mechanically and electrically worn out. The ITE medium voltage switchgear and circuit breakers are original plant equipment. All the old 1970's vintage breakers on plant site will be inspected to see if they can be reconditioned. Breakers that are too damaged will be replaced. The 13.8kV air circuit breakers also have lower terminal insulator issues which increases the costs to recondition them. Since the start of this project, all of the 230kV and 50kV oil circuit breakers have been reconditioned or replaced. This project will continue to recondition the 13.8kV, 4160V, and 480V air circuit breakers.	$ 17,765	$ 19,421	$ 37,186	6/30/2011
216.	60-1055	Navajo Units 1, 2, 3	Reliability	Platen Superheater Pendant Sec Rpr	The 36 platen superheater pendant assemblies are requiring repairs to counter the aggressive sootblower erosion attack from four levels of retract sootblowers in the bottom 30-foot section of the pendant assembly. This section includes less than 5% of the pendent tubing, which has been repeatedly pad welded and repaired. This section of pendant tubing requires replacement to maintain boiler reliability. The bottom 30-foot tubing section will be replaced with upgraded stainless steel tubing to better resist the thinning effects that may cause forced tube leak outages from continual sootblower erosion. This job includes the installation of pendent assembly sections during the Unit 2 overhaul.	$ 35,229	$ 1,630	$ 36,860	6/30/2011
217.	60-0924	Navajo Units 1, 2, 3	Environmental Compliance	Bottom Ash Motor Starters Nav 1-3	Install sealed vacuum technology NEMA motor starters/controllers between the bottom ash conveying pump and hopper jet booster pump breakers and motors.	$ 32,843	$ 3,481	$ 36,324	6/30/2011
218.	CHC0304	Cholla Common	Reliability	RO Unit Addition	The RO unit is essential to plant unit operation. The unit can be purchased at a significantly lower price than a new one and more economically than extending the lease.	$ 33,907	$ 1,569	$ 35,476	6/30/2011
219.	YUC0056	Yucca Common	Safety / Security	Lockout-Tagout System	This project is required to standardize fleet production of lockout-tagout tags, and will reduce the risk of safety events due to human performance error. The Company has benchmarked other companies' best practices resulting in a complete re-write of the lockout-tagout process and procedure. This WA funds the purchase of software and equipment necessary to implement the new best practices for the lockout-tagout process and procedure.	$ 32,046	$ 1,483	$ 33,528	6/30/2011
220.	60-1024	Navajo Units 1, 2, 3	Environmental Compliance	CEM Flow-Opacity Monitor Replace	NGS's Continuous Emissions Monitoring System (CEMS) flow and opacity monitors are obsolete and need to be replaced. Replace the existing flow and opacity monitors and the equipment required to calibrate them.	$ 30,862	$ 1,428	$ 32,290	6/30/2011
221.	60-0907	Navajo Units 1, 2, 3	Safety / Security	Coal Hndling Fire Detection-Protect	Add fire detection and sprinkler piping and deluge nozzles at the appropriate locations. Develop a better zone system in the fire alarm panel program for troubleshooting problems.	$ 30,763	$ 1,423	$ 32,186	6/30/2011
222.	WPC0194	West Phoenix Common	Reliability	Tools - 2011	Misc cap tool for projects	$ -	$ 31,749	$ 31,749	12/15/2011
223.	60-1016C	Navajo Units 1, 2, 3	Reliability	Plant Tools Contingency	This budget item is to cover capital expenditures. Examples of past expenditures from this line item include the purchase of hot water pressure washer, a breaker trip test kit, a pipe threader and Huck railroad tools.	$ 29,364	$ 679	$ 30,043	3/31/2011
224.	60-1027	Navajo Units 1, 2, 3	Reliability	MSS Relay Replacement	NGS's current Main Station Service (MSS) relay is obsolete and has no redundancy. Recent NERC requirements require testing of this relay on a periodic basis. Compliance with other NERC requirements poses operational issues that preclude testing of the relay. Replace the existing relay with a system that includes two relays, adding redundancy which will allow testing to be done with the MSS transformer energized and in service.	$ 23,617	$ 5,893	$ 29,509	12/31/2011

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
225.	FBC90351	Four Corners Unit 4	Reliability	Furnace Temperature Monitor	The purpose of this project is to maintain unit reliability by preventing superheat and reheat tube damage due to high startup flue gas temperatures. Damage occurs from overheating of the tubes which causes cracks and leaks. The infrared based monitoring system will provide information to monitor the flue gas temperatures during startup.	$ 7,490	$ 21,544	$ 29,034	10/27/2011
226.	60-0916	Navajo Units 1, 2, 3	Reliability	Plant Tools-Navajo 1-3	Capital expenditures to comply with sections 15.2 and 17.1 of the Navajo Generating Station Operating Agreement. Examples of past expenditures from this line item include the purchase of hot water pressure washer, a breaker trip test kit, a pipe threader and Huck railroad tools.	$ 27,662	$ 1,280	$ 28,942	6/30/2011
227.	60-1009C	Navajo Units 1, 2, 3	Reliability	Coal Control Graphic Board Replacement	The Coal Control graphics panel, or switchboard, is original plant equipment. It is obsolete; parts are no longer available. The panel serves as the backup to an Allen Bradley PLC5 system, which is the primary method used to control the coal belt system. The panel is also the only way to control the feed rates. NGS will remove the graphics panel, purchase a second Allen Bradley PLC5 system to serve as the backup, and incorporate belt feed rate control into the PLC systems.	$ 26,109	$ 2,013	$ 28,123	10/31/2011
228.	60-0917	Navajo Units 1, 2, 3	Environmental Compliance	Environmental Reg Requirements	Funding to comply, as necessary, with short lead time environmental regulatory requirements at NGS. Future requirements may include RATA testing equipment upgrades, opacity monitoring, particulate monitoring, precipitator controls upgrades, additional ambient air monitoring sites, and other unexpected corrective actions from audits by the EPA, NNEPA, ADEQ, ADHS, ARRA and OSHA.	$ 26,861	$ 1,243	$ 28,103	6/30/2011
229.	60-0923	Navajo Units 1, 2, 3	Environmental Compliance	Potable Water Cartridge Filter	Install a cartridge filter system upstream of the sand filters to remove naturally occurring organic material to eliminate the formation of disinfection by-products.	$ 25,035	$ 1,158	$ 26,193	6/30/2011
230.	RHC0144	Redhawk Common	Reliability	Tools - 2011	Misc tools including : 500 Lb Positioner W/ 12 inch Chuck Price, Tungsten Grinder, Plasma Upgrade, Hole Borer, MS-2 Circuit Breaker and Overload Tester.	$ -	$ 26,157	$ 26,157	12/15/2011
231.	OCC0074	Ocotillo Common	Safety / Security	Lockout-Tagout System	This project is required to standardize fleet production of lockout-tagout tags, and will reduce the risk of safety events due to human performance error. The Company has benchmarked other companies' best practices resulting in a complete re-write of the lockout-tagout process and procedure. This WA funds the purchase of software and equipment necessary to implement the new best practices for the lockout-tagout process and procedure.	$ 23,560	$ 1,090	$ 24,650	6/30/2011
232.	60-0914	Navajo Units 1, 2, 3	Reliability	Furniture and Office Equip Nav 1-3	Purchase, as necessary, furniture and office equipment for NGS. As in past years, this budget line item will be used primarily for on-going replacements and upgrades of office computer systems. Example of past expenditures include the purchase of network storage devices, servers and printers.	$ 23,352	$ 1,080	$ 24,432	6/30/2011
233.	SDC0050	Sundance Common	Reliability	Swgr Breaker Remote Racking, Closing	The remote racking and control will provide additional safety margin to rack in/out breakers and close/trip breakers, without having to de-energize the busses. ARC FLASH studies have shown the incident energy level to exceed level 4, so there is no PPE suitable for the existing incident energy level.	$ -	$ 23,495	$ 23,495	3/30/2011
234.	SAC0063	Saguaro Common	Safety / Security	Lockout-Tagout System	This project is required to standardize fleet production of lockout-tagout tags, and will reduce the risk of safety events due to human performance error. The Company has benchmarked other companies' best practices resulting in a complete re-write of the lockout-tagout process and procedure. This WA funds the purchase of software and equipment necessary to implement the new best practices for the lockout-tagout process and procedure.	$ 21,937	$ 1,015	$ 22,952	6/30/2011

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
235.	CHC0313	Cholla Units 1, 2, 3	Reliability	Video Conferencing Equipment Upgrade	Project is to enhance the Generation Videoconferencing system providing continuity of use, additional capability & connectivity, and provide upgrades to older systems which not only allow additional function.	$ 19,914	$ 921	$ 20,835	6/30/2011
236.	60-1020	Navajo Units 1, 2, 3	Safety / Security	Locomotive Camera System-3	Install an audio and video recording system that is tied to the event recorder on each of the three locomotives that are used as lead locomotives.	$ 19,101	$ 884	$ 19,985	6/30/2011
237.	WPC0154	West Phoenix CC 4	Prevent Failure	BOP Battery Replacement	The existing battery must be replaced to be able to operate the unit and provide emergency power for shutdown in the case of a AC power failure.	$ 18,078	$ 836	$ 18,914	6/30/2011
238.	60-1053	Navajo Units 1, 2, 3	Reliability	Oil Gun Replacement-2	The warm-up oil guns are critical to boiler start-up. Reliability and performance have eroded and maintenance efforts have not been successful. Current equipment uses obsolete technology and parts are costly and difficult to obtain. The retractable mechanism is prone to failure and results in improper atomization of combustion air and fuel oil causing costly delays and risk of fire during start-up. During a cold start, non-preheated combustion air, high excess air, and cold furnace walls that act as black body heat sinks for flame radiation make fuel light-off difficult with current equipment. Flames can be erratic and unstable when fuel is lit, resulting in unburned fuel escaping the flame envelope. This condition creates the risk of fire in the air preheater and electrostatic precipitator. A portion of the material purchases will take place in 2009 using the long lead time budget. Oil guns were replaced on Unit 1 and Unit 3 during the prior overhauls.	$ 17,589	$ 814	$ 18,402	6/30/2011
239.	60-1062	Navajo Units 1, 2, 3	Reliability	Cable Replacement Com	The plant has adopted a policy of installing overhead cable rather than reusing underground raceways for power or control cables because: • Extracting power cable is difficult as the pulling soap, generously applied during construction, has hardened. Efforts to soften the soap are time consuming, labor intensive, and not always successful. • Water is entering electrical manholes and underground raceways, immersing the cable and resulting in degradation. • Failure of the underground raceways is an issue. Borescope inspection of failed pulverizer control cable found the PVC duct joints separated due to continuous vibration. A contractor attempting to reuse underground duct bank for a 13.8kV power feed to Coal Control discovered sand in the duct bank that flushing did not clear. In 2010, NGS will conduct an engineering life reassessment of critical cable feeds based on age, capacity, inspection and failures to determine which areas across the plant site need proactive cable replacement. The study will also determine cable specifications and quantity needed for situational repairs.	$ 16,700	$ 773	$ 17,473	6/30/2011
240.	60-1014C	Navajo Units 1, 2, 3	Reliability	Furniture and Office Equipment	Purchase, as necessary, furniture and office equipment for NGS. As in past years, this budget line item will be used primarily for on-going replacements and upgrades of office computer systems. Example of past expenditures include the purchase of network storage devices, servers and printers.	$ 15,975	$ 739	$ 16,714	6/30/2011
241.	60-0906	Navajo Units 1, 2, 3	Reliability	Maintenance Training Equip Nav 1-3	Purchase a group of learning systems and simulators that will allow maintenance employees to learn necessary skills in a laboratory setting.	$ 14,837	$ 686	$ 15,523	6/30/2011
242.	60-1012	Navajo Units 1, 2, 3	Reliability	Spare Limestone Prep Ball Mil Motor	The scrubber ball mill motors have been unreliable since the scrubber was put in-service. These motors are sourced from outside the United States and have a long lead time. Implications from violating the Clean Air Act are such that NGS seeks to keep the scrubbers operational at all times.	$ 12,861	$ 298	$ 13,158	3/1/2011

Line No.	WA#	Plant & Unit	Category	Project Description	Purpose	Project Cost to Date 12/31/2010	Costs to Complete	Projected Closed Cost	Estimated In-Service Date
243.	FCC90325	Four Corners Units 4 & 5	Reliability	Ash Flush Pump Motor Replacement	The purpose of this project is to maintain unit reliability. There are two motors, east and west, east motor has been rebuilt multiple times and is nearing the end of useful life. Repaired cracks in all four quadrants of the end housing makes future repairs questionable. A balancing analysis of the motor shows high vibration in both the inboard and outboard bearings and indicates that a balance-shot will most likely not decrease the vibrations.	$ -	$ 13,100	$ 13,100	2/15/2011
244.	60-1002C	Navajo Units 1, 2, 3	Reliability	900 CFM Air Compressor	Replace a 1993 Ingersoll Rand air compressor, NPG 621, with a new air compressor.	$ 11,325	$ 524	$ 11,849	6/30/2011
245.	60-1017	Navajo Units 1, 2, 3	Environmental Compliance	Environmental Regulatory Contingency	Funding to comply, as necessary, with short lead time environmental regulatory requirements at NGS. Future requirements may include RATA testing equipment upgrades, opacity monitoring, particulate monitoring, precipitator controls upgrades, additional ambient air monitoring sites, and other unexpected corrective actions from audits by the EPA, NNEPA, ADEQ, ADHS, ARRA and OSHA.	$ 10,343	$ 80	$ 10,423	1/31/2011
246.	60-1003	Navajo Units 1, 2, 3	Reliability	10000 lb Forklift	Replace a 1997 Caterpillar 10,000 lb. forklift, NPG 667, with a new 10,000 lb. forklift.	$ 5,687	$ 263	$ 5,951	6/30/2011
247.	60-0918	Navajo Units 1, 2, 3	Safety / Security	Coal Convey Emergency Light-Signage	Install emergency lighting and signage in coal conveying areas where this equipment is lacking.	$ 2,646	$ 122	$ 2,768	6/30/2011
248.	EIS Credits	Many Units	Environmental Compliance	Future EIS Credits - jobs not yet Designated	"Environmental Improvement Surcharge" is money to apply to jobs that qualify as environmental projects. Funds collected from the EIS surcharge are separately identified by APS and recorded as a liability. Use of these funds on qualified EIS improvement costs will reduce the regulatory liability and be recorded as Contributions in Aid of Construction ("CIAC") and applied against the capital costs of qualified EIS improvement projects during construction or upon acquisition, as appropriate.	$ -	$ (2,404,368)	$ (2,404,368)	6/30/2012
249.	EIS Credits	Many Units	Environmental Compliance	Future EIS Credits - jobs not yet Designated	"Environmental Improvement Surcharge" is a bucket of money to apply to jobs that qualify as environmental projects. Funds collected from the EIS surcharge are separately identified by APS and recorded as a liability. Use of these funds on qualified EIS improvement costs will reduce the regulatory liability and be recorded as Contributions in Aid of Construction ("CIAC") and applied against the capital costs of qualified EIS improvement projects during construction or upon acquisition, as appropriate.	$ -	$ (4,332,312)	$ (4,332,312)	12/31/2011
250.	60-0819A EIS	Navajo Units 1, 2, 3	Environmental Compliance	EIS Credit for Low Nox Burners	"Environmental Improvement Surcharge" is a bucket of money to apply to jobs that qualify as environmental projects. Funds collected from the EIS surcharge are separately identified by APS and recorded as a liability. Use of these funds on qualified EIS improvement costs will reduce the regulatory liability and be recorded as Contributions in Aid of Construction ("CIAC") and applied against the capital costs of qualified EIS improvement projects during construction or upon acquisition, as appropriate.	$ (5,259,081)	$ (203,053)	$ (5,462,134)	4/3/2011
251.	CHC0335	Cholla Unit 2	Reliability	Insurance Reimbursement	Reimbursement for Cholla 2 Failure (2010).	$ -	$ (7,356,206)	$ (7,356,206)	7/1/2011
252.	Total Fossil Post-Test Year Plant Additions					$ 70,483,697	$ 85,785,565	$ 156,269,262	

Randall K. Edington

TESTIMONY OF RANDALL K. EDINGTON

On Behalf of Arizona Public Service Company

Docket No. E-01345A-11-_____

June 1, 2011

Table of Contents

I. INTRODUCTION 1
II. SUMMARY 2
III. INTRODUCTION TO NUCLEAR GENERATION. 3
IV. COST EFFICIENCIES AT THE NUCLEAR PLANT. 27
V. CONCLUSION 49
Nuclear Generation Post-Test Year Plant Additions..... Attachment RKE-1

TESTIMONY OF RANDALL K. EDINGTON
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-11-_____)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. Randall K. "Randy" Edington, Palo Verde Nuclear Generating Station, P.O. Box 52034, Station 7602, Arizona 85072-2034, Executive Vice President - Nuclear and Chief Nuclear Officer at Palo Verde Nuclear Generating Station ("Palo Verde," "the Station," or "the Plant").

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE AND BACKGROUND?

A. I have over 38 years of operational experience in the nuclear industry. My career began with 8 years of service in the Navy's nuclear submarine program. Following my discharge from the Navy in 1981, I joined Entergy's Arkansas Nuclear One ("ANO") where I obtained my Reactor Operator and Senior Reactor Operator licenses.

While working at ANO, I obtained a Bachelor of Science degree in physical science with an emphasis on nuclear physics from Arkansas Technical University and Master of Science degree in Operations Management from the University of Arkansas. From 1981 to 1998, I worked in various management positions of increasing responsibility, including Outage Manager, Operations Manager, Plant Manager, and Site General Manager.

In 1998, I left ANO and worked for Entergy at the executive level of several other nuclear power plants, all of which were experiencing performance issues, including River Bend, Indian Point, and Cooper nuclear stations.

In January 2007, I was hired by Arizona Public Service ("APS" or "the Company") as the Senior Vice President - Nuclear and Chief Nuclear Officer to

lead Palo Verde through performance improvement after the Station had experienced a decline in performance since the mid-2000s. I was promoted to Executive Vice President in November 2007.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony provides general information regarding Palo Verde relating to the rate case, and supports APS's request to include the Company's share of Palo Verde capital expenditures in rate base and APS's share of Palo Verde's operations and maintenance ("O&M") expenses in its cost of service.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The mission of Palo Verde is to SAFELY and efficiently *generate* electricity for the *long term*. Our responsibility as stewards of our customers' and other stakeholders' investment is shaped by one certainty: SAFETY. Our responsibility as the NRC's licensee for the operation of Palo Verde is to protect public health, safety, and the environment.

When I assembled my new management team in 2007, we committed ourselves – in writing – to the mission of SAFELY and efficiently *generating* electricity for the *long term*. Our first priority was then, is now, and will continue to be, SAFETY. My testimony will point out some of the unique attributes of Palo Verde, some of which provide advantages, some of which provide disadvantages. I will also point out how the Palo Verde team focused its activities over the past several years on recovering safety and regulatory margin by improving equipment and processes. We have moved at a controlled and deliberate pace to implement these improvements, and are shifting our emphasis to cost efficiency.

We believe these priorities were and are in keeping with the best interest of our customers and other stakeholders.

In my testimony, I also identify and discuss the major capital projects placed into service during 2010, as well as those to be placed in service during 2011 and the first two quarters of 2012, as reflected in the post-Test Year plant additions pro forma, as can be seen on Standard Filing Requirements Schedule B-2, page 2, column 5. APS's share of these capital improvements in the post-Test Year plant additions pro forma represents a nearly $120 million investment in greater safety, reliability and efficiency.

III. INTRODUCTION TO NUCLEAR GENERATION.

Q. PLEASE DESCRIBE NUCLEAR POWER GENERATION.

A. All matter (natural and man-made) is comprised of elements that contain a distinct number of positively charged particles (protons) and neutrally charged particles (neutrons) in their nucleus. Negatively charged particles (electrons) orbit around the element's nucleus. Each element has an equal number of protons and electrons, but different forms of each element (isotopes) have different numbers of neutrons.

The presence or absence of neutrons may cause an isotope to become unstable and its nucleus will split (fission) in order to become more stable. The fission reaction produces a tremendous amount of energy relative to the size of the particle.

Nuclear power generation uses the energy produced upon the fission of the uranium 235 isotope ("U_{235}") to create steam, which subsequently turns a turbine and the attached electrical generator resulting in the production of electricity.

Q. WHAT ARE BASE LOAD PLANTS AND WHAT MAKES NUCLEAR POWER BASE LOAD PLANTS UNIQUE?

A. Base load electricity generating plants are the production facilities used to meet the steady and continuous needs of electricity to run our homes, businesses, hospitals, schools, military bases and other facilities. Nuclear power plants are ideal base load generating plants because their operations are predictable and reliable and they have the lowest operating costs and highest capacity of other traditional base load plants.

Q. WHAT ARE OTHER UNIQUE ASPECTS OF NUCLEAR POWER PLANTS IN COMPARISON TO TRADITIONAL FOSSIL FUELED PLANTS?

A. Nuclear power plants in the United States are regulated by the Nuclear Regulatory Commission ("NRC"). As a condition of its NRC license, each station is required to develop and maintain strict plant operating standards, plant designs, and technical specifications that must be complied with to meet the license requirements. If an anomalous situation occurs, technical specifications require that certain actions must be performed and conditions met within specific timeframes in order to continue to operate the unit. In some cases, when these prescribed actions cannot be met within predetermined timeframes, the technical specifications require that the unit be taken out of service. NRC regulations, radiological conditions, and prescriptive operating procedures require the unit to follow a specific process for shutdown, outages, and restart.

Nuclear power plants, especially those in the United States, are strictly regulated to assure their safety. The operating requirements are vastly different from those applicable to coal or gas-fired plants of similar size. For example, the radiological conditions of a nuclear plant are highly controlled and monitored, and access to specific areas is restricted during normal plant operations. When a nuclear plant is taken out of service, access to certain areas is restricted until

radiological, temperature, and other conditions are met. Despite Palo Verde's success in minimizing the effect of radiological conditions during outages, the ability of employees to work during outages is still more restricted than comparable maintenance or repair in a fossil fueled station.

Each U.S. nuclear station contains multiple systems as well as engineering practices and operational features that create redundancy – or multiple barriers – to ensure safe operations. Regulations and maintenance practices in nuclear stations are in place to replace, repair, and ensure the safety margin of the primary and secondary systems. This means that the unit may be down-powered or removed from service to repair a system that does not directly impact the operations or output of the plant but is done to ensure the safe operation of the back-up systems. Palo Verde has specific operations and maintenance procedures (and corresponding training for personnel) that control plant operation. These procedures cover not only normal plant operation, but a multitude of other conditions such as abnormal operations and emergencies. As a result, plant operators have extremely limited discretion in how the plant is to be operated in any specific condition. By contrast, fossil fueled units do not have strict technical specifications that require the unit to be taken out of service under such circumstances.

Additionally, from the time a nuclear unit is shut down for refueling, 100 hours are needed to ensure the decay heat from the reactor core has reached a point that it is safe to begin refueling operations. From shutdown conditions to returning to the grid takes about two days, and return to 100 percent power takes an additional one to two days. In contrast, to remove and return a gas or coal plant to service can be achieved in as little as, or less than, one day.

Finally, nuclear power plants do not rely on the combustion of carbon-based fossil fuels (such as coal and natural gas) that are utilized at other base load fossil fueled plants. Nuclear plants' heat source is the fission reaction of U_{235}. Therefore, nuclear plants do not produce green house gases or other air pollutant emissions such as sulfur dioxide, nitrogen oxides, or particulate matter during their operation. Since it started operation in 1986, the electricity generated by Palo Verde has enabled its Participant Owners to avoid the emission of 483.7 million tons of carbon dioxide, 253,481 tons of sulfur dioxide (which contributes to acid rain), and 618,000 tons of nitrogen oxides (which contributes to the formation of ground level smog).

Q. WHAT IS UNIQUE ABOUT THE PALO VERDE NUCLEAR GENERATING STATION?

A. Palo Verde has a number of unique attributes, some of which provide advantages while others provide disadvantages.

FOOTPRINT. Palo Verde is located on a 4,286 acre site approximately 55 miles west of Phoenix, and consists of three separate standardized nuclear generating units, a water reclamation facility, and a variety of common support facilities. Palo Verde is the largest nuclear power plant in the U.S. and is capable of generating over 4,000 megawatts of electricity ("MWe"). Furthermore, it is the first and only power plant in the country (of any fuel source) to produce more than 31 million megawatt-hours ("MWh") in one year. Indeed, Palo Verde Unit 1 generated more electricity than any single nuclear unit in the world in 2009 (11,589,723 MWh) followed by Palo Verde's Unit 2 world leading production in 2010 (11,652,972 MWh).

Unfortunately, Palo Verde's large footprint also gives it a disadvantage relative to the country's three other three-unit nuclear power plants (which cover 840, 700

and 510 acres). The sheer size requires larger physical security systems and a greater number of security guards in order to meet operational and regulatory requirements.

NUCLEAR STEAM SUPPLY SYSTEM. The three Palo Verde generating units are virtually identical Combustion Engineering System 80 ("CE System 80") pressurized water reactors ("PWR").

The three virtually identical units provide an advantage with respect to operational economies of scale. Although each unit has its own NRC operating license, there is a common design and licensing basis for the three units. Therefore, there are efficiencies associated with the design, engineering, and implementation of modifications to the three units, as well as a common set of operations and maintenance procedures for the three units. As such, the development and maintenance of procedures can be centralized into one organization and training of operations and maintenance crews can be conducted on a Station-wide basis rather than a unitized basis.

Nevertheless, the risks associated with operating any three units of virtually identical design provide disadvantages. Specifically, a degraded or non-conforming condition in any one unit must immediately be analyzed in the other two units to determine the extent of that condition (if one exists) in the other units. Therefore, a design or maintenance issue in any unit can be transportable to all units and consequently increase the risk of a three-unit shutdown. Additionally, while the CE System 80 was designed to maximize reliability and performance, the units each have approximately 9,500 more components than typical PWRs. These additional components require the conduct of more

operations and maintenance, the purchase of more components, and the stocking and storing of those components in the warehouse.

Moreover, Palo Verde's CE System 80 reactor core is designed for refueling every eighteen months. Therefore, Palo Verde requires two refueling outages every year. This condition places as much emphasis on outage performance at Palo Verde as operational performance – making Palo Verde "in the outage business."

In addition, Palo Verde is the only nuclear plant in the U.S. with its ultimate nuclear safety heat sink (the spray ponds) located immediately next to the units within the protected area. This requires additional monitoring and staging and logistics of equipment stored in the protected area.

Finally, each of the units has its own control room and chemistry laboratory. Therefore, staffing those positions to meet regulatory and operational requirements demands greater human resources than employed at most two-unit nuclear plants, which often share a control room or chemistry laboratory.

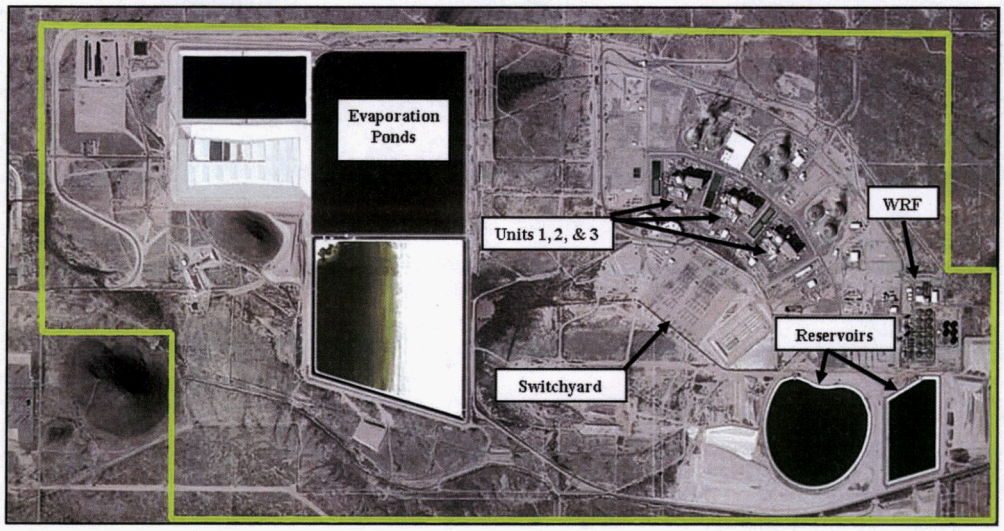
WATER RECLAMATION FACILITY. One aspect of Palo Verde that distinguishes it from any other nuclear power plant in the world is that it is not located on or near a large body of water. Therefore, it must obtain water from other sources and must discharge any waste water to a system that will not adversely impact surface or underground water supplies. This unique aspect of Palo Verde is a necessary cost of doing business that is not incurred at any one of the world's nuclear power plants.

Palo Verde purchases its cooling water from the waste water treatment plants of the Valley (Glendale, Mesa, Phoenix, Scottsdale, and Tempe (the Subregional

Operating Group ("SROG"), and Tolleson). The SROG and Tolleson waste water treatment plants' effluent gravity flows 28 miles to the Hassayampa River basin due to the natural decrease in elevation from 91st Avenue to the Hassayampa River. From the Hassayampa River, it is then pumped eight miles to Palo Verde due to the natural increase in elevation from the Hassayampa River to Palo Verde.

Once received at Palo Verde, the effluent is treated at the Palo Verde Water Reclamation Facility ("WRF") to remove ammonia and minerals that would otherwise damage or cause scaling on vital plant cooling components. After being treated, the water is stored in either one of the Station's on-site 45 acre or 85 acre reservoirs. When cooling water is needed, it is pumped to the cooling towers where it is cycled more than 20 times before a small amount (less than 5%) is discharged to one of the Station's three evaporation ponds.

The WRF operations described above require a separate physical plant with a staff of approximately 140 people which, along with chemicals, materials and supplies, increases Palo Verde's operating costs by more than $1.00 per MWh above all other nuclear plant in the world. Additionally, as a zero liquid discharge plant, Palo Verde must also operate and maintain three very large evaporation ponds (covering 250, 220, and 180 acres, respectively) for the life of the Plant until all standing water evaporates. An aerial photo of Palo Verde is provided below:



Q. COULD YOU PLEASE EXPLAIN APS'S ROLE IN OPERATING PALO VERDE?

A. Palo Verde is owned by seven southwest region electric utilities ("Participant Owners") with various ownership interests: APS (29.1%), Salt River Project (17.49%), El Paso Electric Company (15.8%), Southern California Edison Company (15.8%), Public Service Company of New Mexico (10.2%), Southern California Public Power Authority (5.91%), and Los Angeles Department of Water and Power (5.7%). Pursuant to the contract between and among the Palo Verde owners (referred to as the Arizona Nuclear Power Project Participation Agreement), APS is the NRC operating license holder and operating agent of Palo Verde. In this regard, APS manages the employees and contractors working at Palo Verde, and makes all decisions with regard to the safe and reliable operation of the Station such as scheduling maintenance and refueling outages, shutting a unit down for an outage when an issue arises, and restarting a unit after an outage. APS confers with, and receives approval from, the Participant Owners on a number of things, including all major capital projects. The involvement of the Participant Owners in Palo Verde operations is facilitated by several committees, including the Administrative Committee, which is comprised of

Participant Owner senior executives, and of which I am the Chairman, and the Engineering and Operating Committee.

As I mentioned earlier in my testimony, certain aspects of nuclear power plant operations are affected by regulations promulgated by the NRC. As has been demonstrated by the tragic earthquake and tsunami in Japan, and their impact on the Fukushima Daiichi nuclear power plant, the operation and management of a nuclear power plant demands a high level of expertise and a healthy respect for the special and unique nature of nuclear technology. As the NRC operating license holder, APS is given tremendous responsibility – and the corresponding accountability – to operate Palo Verde in a manner that does not adversely impact or threaten to adversely impact public health and safety, and the environment.

Q. WHAT ARE CURRENT TERMS OF THE PALO VERDE NRC OPERATING LICENSE?

A. The Unit 1 operating license was approved by the Nuclear Regulatory Commission ("NRC"), on May 30, 1985. In 2006, the Unit 1 design electrical rating was increased by 68 MWe (from 1,265 MWe to 1,333 MWe) as a result of the 2005 steam generator and low pressure turbine replacements.

The Unit 2 operating license was approved by the NRC, on April 23, 1986. In 2004, the design electrical rating of Unit 2 was increased by 71 MWe (from 1,265 MWe to 1336 MWe) as a result of the 2003 steam generator and low pressure turbine replacements.

The Unit 3 operating license was approved by the NRC on November 25, 1987. In 2008, the design electrical rating of Unit 3 was increased by 65 MWe (from 1,269 MWe to 1,334 MWe) as a result of the steam generator and low pressure turbine replacements in 2007.

On December 11, 2008, APS submitted an application to the NRC to renew the operating licenses of each unit in order to extend the licenses of each unit for an additional 20 years. The NRC approved the license renewal application on April 21, 2011. The new expiration dates for the NRC operating licenses for the three Palo Verde Units are June 1, 2045, April 24, 2046, and November 25, 2047.

Q. WHAT OPERATING PHILOSOPHY AND ASSOCIATED PLANS AND PROGRAMS DOES APS HAVE IN PLACE TO MEET ITS RESPONSIBILITIES AS THE NRC LICENSEE OF PALO VERDE?

A. APS is a values driven organization. Our values are Safety, Integrity and Trust, Respect, and Accountability. These values influence our behaviors and are revealed through the way we act. Values guide us to do the right thing. At Palo Verde, we believe how we get the job done is as important as getting the job done. Ultimately, our values and our behaviors define our culture and have a fundamental influence on how and why we make decisions and how we work together at Palo Verde.

When faced with an issue, we ask ourselves: What is the right thing to do? We discuss our points of view professionally and respectfully to determine the right course of action by making conscious, informed decisions. Furthermore, we have an obligation to protect the assets of the organization, and we achieve this by living our values each day with each decision we make. Achieving excellence benefits us, our owners, all of our stakeholders, and our community.

We recognize that nuclear technology is special and unique and accept the significant responsibility in operating a nuclear power station. As such, our values and mission statement - to SAFELY and efficiently *generate* electricity for the *long term* - drive the operation.

To effectively accomplish its mission, Palo Verde management utilizes a Leadership Model that describes the characteristics and behaviors each employee should demonstrate. It describes our values, fundamental behaviors, key program areas, and how we measure and monitor success. Moreover, every employee is a leader regardless of title or position. To effectively accomplish its mission, Palo Verde management utilizes strategic planning, long range planning, and business planning processes.

Additionally, Palo Verde's business planning processes consist of a building block approach in which areas of emphasis (SAFETY, Operational Focus, Generation, and Cost) support effective mission accomplishment. An illustration of the Palo Verde Business Plan is provided below.

SAFETY is one of APS's core values and is essential to Palo Verde's mission.[1] To SAFELY and efficiently *generate* electricity for the *long term* is the common denominator that links every employee and every department at Palo Verde. Indeed, Station and individual alignment to the mission are key to the Station's long-term success. There are four elements of SAFETY that are embraced at Palo Verde: Nuclear Safety, Industrial Safety, Radiological Safety, and Safety

[1] Because safety is of the utmost importance to the Company, and is addressed in its Values and various levels of the Leadership Model, the competency detail will be addressed primarily in this section to avoid redundancy.

Culture. Our employees embrace SAFETY and make personal and conscious decisions to ensure the safety of themselves, their co-workers, APS's customers, and the public at large.

NUCLEAR SAFETY. Personnel at the Station exhibit the right behaviors and are committed to keeping employees and the public free from danger, injury, or undue risk from the operation of Palo Verde. Employees at Palo Verde:

- Understand their role with Station probabilistic risk;
- Maintain a questioning attitude;
- Challenge assumptions and beliefs and involve others;
- Understand the potential consequences of actions before they are taken;
- Identify and promptly report problems through initiation of a Palo Verde Action Request ("PVAR") and take immediate action when appropriate;
- Use conservative decision making;
- Model organizational values and adhere to the highest standards that support nuclear safety;
- Follow procedures, work instructions, and plant postings;
- Ensure that component manipulations are performed using procedures or work instructions; and
- Ensure that reported problems are properly reviewed, prioritized, and resolved.

INDUSTRIAL SAFETY. Every employee is involved in activities and decisions that impact their safety and health. We take individual accountability for our own health and safety and the health and safety of others. At Palo Verde we work safely and reliably by following proper industrial safety work practices and rules. We challenge unsafe behavior and maintain a safe work area. Employees at Palo Verde:

- Understand steps to take for accident prevention;
- Recognize, report, and correct unsafe conditions;
- Assess conditions at the beginning and throughout an activity;
- Identify existing and potential hazards;
- Eliminate (preferred) or manage/mitigate hazards;
- Ensure tagging boundaries are appropriate for work being performed;
- Use appropriate Personnel Protective Equipment ("PPE");
- Ensure that safety briefings are conducted;
- Frequently conduct safety observations;
- Recognize individuals that reinforce safe behaviors;
- Correct inappropriate behaviors;
- Use operating experience; and
- Conduct prompt thorough, detailed accident investigations.

RADIOLOGICAL SAFETY. At Palo Verde we are aware of and follow proper radiation work practices to protect our employees and the public from the hazards of radiation. Employees at Palo Verde:

- Understand and maintain strict compliance with Radiation Exposure Permits;
- Minimize the spread of contamination during work activities;
- Practice maintaining dose As Low As Reasonably Achievable ("ALARA") using time, distance and shielding;
- Adhere to radiological boundaries and postings;
- Anticipate potential changes in radiological conditions;

- Ensure radiological briefings are conducted and actively participate in radiological briefings;
- Respond properly to dosimeter and area alarms;
- Identify dose-reduction activities proactively;
- Exercise "stop work" if radiological conditions change and get additional management involvement;
- Support changes in processes to reduce dose; and
- Implement emergency plan controls to protect employees and the public.

SAFETY CULTURE. As defined by the Institute of Nuclear Power Operations ("INPO") nuclear safety is, "an organization's shared values and behaviors - modeled by its leaders and internalized by its members - that serve to make nuclear safety the overriding priority." Moreover, "a safety-conscious work environment (freedom to raise concerns without fear of retribution) is but one (albeit important) element of a strong nuclear safety culture." A strong safety culture is critical to achieving Palo Verde's mission. With broad industry input, INPO developed the following eight safety culture principles:

- Everyone is personally responsible for nuclear safety;
- Leaders demonstrate commitment to safety;
- Trust permeates the organization;
- Decision making reflects safety first;
- Nuclear technology is recognized as special and unique;
- A questioning attitude is cultivated;
- Organizational learning is embraced; and
- Nuclear safety undergoes constant examination.

Palo Verde makes nuclear safety the overriding priority by modeling the safety culture principles during our daily activities, which provides a solid foundation for nuclear safety.

OPERATIONAL FOCUS. For the Plant to remain in excellent material condition, Palo Verde embraces a culture of common goals and priorities. Excellence in Operational Focus requires that the Station concentrate on SAFETY, exercise sound decision making and judgment, and maintain a proper operational alignment. Palo Verde exhibits the highest level of craftsmanship, enhancing equipment reliability and system integrity. To this end, we minimize rework and place a high degree of importance on our preventive maintenance and foreign material exclusion programs. Establishing an environment where craftsmanship can thrive and grow plays a key role in the Station's continued journey to excellence.

INPO maintains a document titled *The Principles for a Strong Plant Operational Focus*, which outlines five areas of focus to achieve operational excellence. Palo Verde places high emphasis on the model and has incorporated the principles into the Station's Business Plan. The five focus areas are:

- High levels of reliability and ample operating margins are relentlessly pursued for equipment that is needed to monitor and control the Plant;
- Equipment removed from service for planned evolutions is scheduled and degraded Plant conditions are managed such that the risk of operational transients and the burden to those operating the Plant are maintained low;

- Plant activities are performed in a manner that prevents unexpected operational events, misalignment of Plant equipment, and impediments to responding to events by those controlling the Plant;
- Organizational roles, responsibilities, processes, procedures or infrastructure are established such that unexpected operational conditions can be promptly and adequately managed; and
- The concepts of Plant operational focus are understood by all levels in the organization.

LONG-TERM GENERATION[2] AND COST EFFECTIVENESS.

To continue SAFELY and efficiently *generating* electricity for the *long term*, Palo Verde takes a strategic view of operational costs. We invest in our people and the Plant to maintain excellent material condition, while remaining cognizant of our budget and resources. Although cost-effective is not synonymous with cheap or least-expensive, the Station does operate as a low-cost generator of electricity without compromising effectiveness and quality. Moreover, as a multi-unit, compact fleet, it is prudent to maintain appropriate levels of resources with adequate margins to ensure continuous SAFETY and effectiveness. Station personnel strive for the simplest solutions at the appropriate cost. Nevertheless, Palo Verde requires high quality reliable equipment and it cannot compromise SAFETY, effectiveness, and quality for cost because the end result will be a reduction in the generation of power.

Q. WHAT IS MANAGEMENT DOING TO IMPROVE PERFORMANCE?

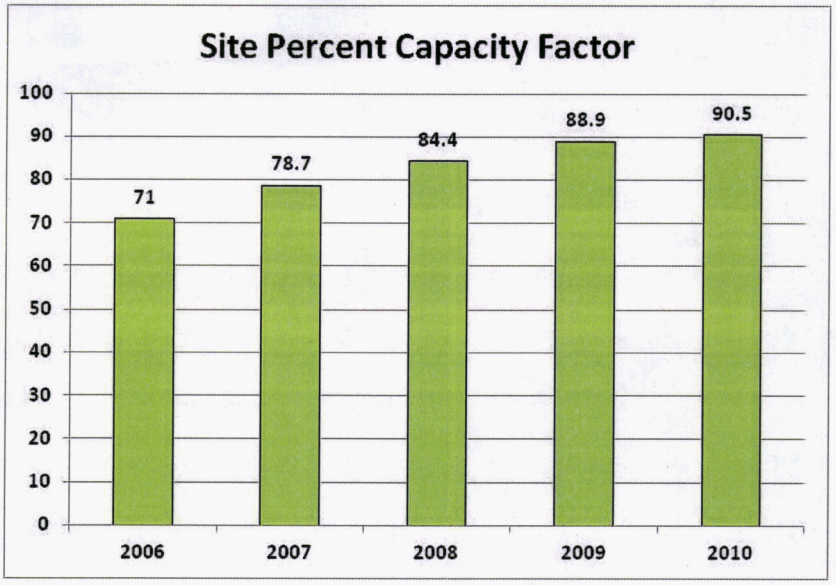
A. The Business Plan serves as an anchor to Station improvement efforts. Its five core building blocks are depicted in red because they are critical elements that we

[2] Generation, in particular base load generation, was addressed in detail above.

continue to focus on. The areas of emphasis are Equipment, People, Problem Identification and Resolution, SAFETY, and Knowledge and Training.

PLANT EQUIPMENT. We are intolerant of equipment failures and everyone takes ownership for equipment reliability. Everyone proactively monitors and takes timely action to ensure Station equipment operates reliably with maximum availability through the operating cycle and that standby safety equipment operates on demand. For example, the Station enlists committees to focus staff on sustained equipment performance improvement, including Equipment Reliability, Long Range Planning, Top 10, and Plant Health Committees to address the life cycle of equipment and long range planning needs. With funding from operations and maintenance ("O&M") and capital budgets now suitably established and focused project management processes, the Station has improved equipment performance and is now achieving higher capacity factors. For example, a modification was recently implemented to allow for the cross connection of the air supply used for instrumentation with the air supply for general services. This modification allowed the Station to avoid a Unit 2 short notice outage in 2010, which directly contributed to that unit's exceptional annual capacity factor. Additionally, the Station recently implemented a modification of the refueling water tank instrumentation. This modification replaced valves with more reliable components, which directly contributed to increased nuclear safety system reliability.

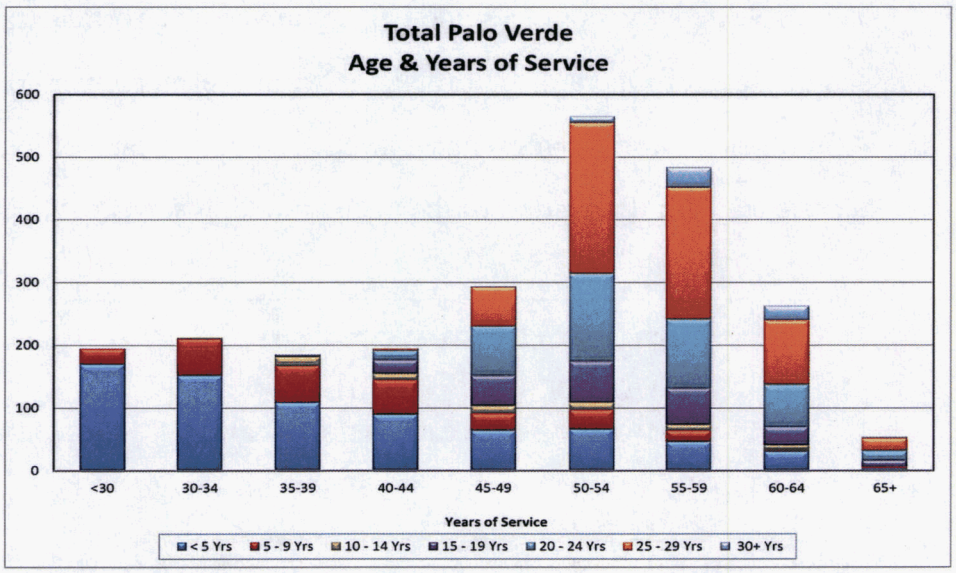
Although Palo Verde's performance is improving and is moving into the top half of the industry, continued success is dependent on uncompromising goals regarding long term performance. A graph of capacity factor performance is provided below:



PEOPLE. People are Palo Verde's most valuable asset. They define who we are and make the difference in Palo Verde's success. Given the complexity of the equipment and technology required to operate a nuclear power plant, the Station requires a motivated, highly skilled, and reasonably compensated work force. Palo Verde is committed to driving excellent performance with comprehensive hiring and talent management strategies for long-term development of skills, knowledge, and retention of Station personnel. To achieve long term results and ensure leadership effectiveness and continuity, the Business Plan requires adequate resources to define and assess performance standards, recruit diverse talent, continuously develop our workforce, and carry out knowledge transfer efforts. Palo Verde recognizes and rewards excelling performance and behavior which ultimately results in increased plant performance and reduced costs.

Since 2006 a total of 631 employees have left Palo Verde for retirement and various other reasons. As of December 2010, 889 employees of the 2,400 employed at Palo Verde are over 55 and of that number, 700 have 20+ years with the Company. Furthermore, within five years an additional 410 employees will reach age 55 and have 20 years of service. To further the dilemma, the nuclear

industry as a whole will lose 35% of its workforce to retirement within the next five years. As such, recruiting high-quality candidates will be increasingly competitive. Although the number of enrolled students in nuclear engineering programs has increased from 500 in 1998 to 4,700 in 2010, there still remains a critical shortage of skilled workers to operate the Plant.[3] A chart illustrating the age demographics at Palo Verde is provided below.



Nevertheless, an aggressive new hire initiative is under way to sustain Palo Verde's long-term health and productivity. To address the number of expected retirements in the next five years and to ensure that key areas of the organization are staffed appropriately, strong recruiting efforts are essential. Targeted hiring includes recruiting top sources of diverse talent with a focus on quality. Succession planning begins with the hiring process. Moreover, extensive training to develop knowledge and experience is required to ensure the Station continues to operate SAFELY and efficiently for the *long term*.

[3] *Nuclear Energy – Just the Facts*. Nuclear Energy Institute, June 2010.

For example, the typical timeframe for an individual to stand shift as a Senior Reactor Operator is eight years, including formal training and job experience. This time period includes three months of nuclear generic fundamentals training, five months of non-licensed operator systems training, and over two years of time on-shift to complete the requirements to be a fully qualified non-licensed operator. Once selected for the license training class, a candidate is required to complete fifteen months of formal training to become a Reactor Operator and, when selected for upgrade, another 15 months of formal training to become a Senior Reactor Operator. In total, a Senior Reactor Operator undergoes almost 40 months of formal training as well as many years of on-shift training and experience. An illustration of the hiring model is provided below.

PROBLEM IDENTIFICATION AND RESOLUTION. This focus area is the heart of the Station's continuous improvement effort. It drives the way the Station identifies issues, evaluates and trends problems, and develops and implements appropriate actions to correct current problems and prevent future issues. Leaders promote problem identification, timely and thorough evaluation of conditions and development and implementation of timely corrective actions.

Effective problem identification and resolution drives down costs by identifying problems before they become material issues and require significant financial resources to correct. Employees live the Operating Experience model, "The right Information to the right People in time to make a Difference!"

SAFETY. As discussed in detail above, SAFETY is key to Palo Verde's success. The culture is such that employees own nuclear, industrial, and radiological safety. Employees value SAFETY and recognize the benefit of a strong nuclear safety culture and safe work behaviors. Indeed, they help each other to achieve an injury-free workplace.

In our drive to achieve an injury-free workplace, we have established a goal to achieve the Occupational Safety and Health Administration ("OSHA") Voluntary Protection Program ("VPP") Safety Through Accountability and Recognition ("STAR") recognition, the highest level of VPP status. In practice, VPP sets performance-based criteria for a managed safety and health system, invites companies to apply, and then assesses applicants against the program's criteria. The program is designed to encourage employers and employees to go above and beyond industry standards and improve existing safety programs.

Palo Verde has established a core team and is in the process of preparing the application for VPP STAR status. Approval as a VPP STAR site is OSHA's official recognition of the outstanding efforts exhibited by employers and employees to achieve exemplary occupational safety and health performance. Moreover, it is validation that a safe plant is a cost effective plant in that injuries and associated time off from work are minimized.

KNOWLEDGE AND TRAINING. The Station operates on the premise that knowledge is the foundation upon which we build. Personnel are encouraged to

increase their knowledge on a daily basis. Indeed, knowledge and training are key strategic tools to develop the workforce and improve overall Station performance in a safe and reliable manner. The self-assessment and corrective action processes are used to identify training solutions that can enhance safe and reliable Plant operations. We have a passion for the pursuit of knowledge and recognize this goes beyond the classroom, laboratory, or other formal training – learning opportunities exist with every task we do. We look for these opportunities across organizational boundaries and seek ways to transfer knowledge from each other and the industry. Furthermore, as I previously stated, recruiting and training new hires are of the utmost importance to Palo Verde given the potential future loss of nearly one-third of the Palo Verde's workforce by the year 2015.

Finally, Station management has a goal of leading the industry in SAFETY, Knowledge and Training, Craftsmanship and Field Focus, which have long term benefits to ensure Palo Verde's continued success. We are also promoting leadership by encouraging personnel to volunteer on committees outside the Plant, whether they are industry affiliations or non-profit organizations. For example, I am Chairman of INPO's Executive Advisory Group, Vice Chair of the PWR Owner's Group, Chairman of the Nuclear Energy Institute ("NEI") Workforce Working Group, and a member of the NEI Nuclear Strategic Issues Advisory Committee Steering Group.

Q. PLEASE DISCUSS THE ARIZONA CORPORATION COMMISSION PERFORMANCE STANDARD AND COMPARE IT TO PALO VERDE'S PERFORMANCE.

A. In 2010, Palo Verde performed well, achieving its best production year ever, generating over 31 million megawatt-hours ("MWh"), which yielded an overall Station capacity factor of 90.5%. At the Station level, this performance would have ordinarily brought Palo Verde within the first tier classification used in the

APS Nuclear Performance Reporting Standard ("NPRS"). Indeed, Unit 2 had a record year, generating more than 11.6 million MWh and achieving a capacity factor of 101.2%. Furthermore, despite Unit 3's planned refueling outage, it achieved a capacity factor of 89.1%, generating 10.2 million MWh.

Even so, the rigor of the NPRS is such that, notwithstanding the high performance of Units 2 and 3, APS still reported unit performance at the more detailed second tier NPRS level because Unit 1 missed the 82% capacity factor forecast provided in the 2010 NPRS report by one percentage point. Unit 1 generated 9.3 million MWh, resulting in a capacity factor of 81%, due primarily to the planned refueling outage and two short forced outages.

The Unit 1 and Unit 3 refueling outages included major equipment capital projects, which will be described in more detail in the portion of my testimony below that describes major capital projects. Briefly stated, two of these projects were installation of new Reactor Vessel Heads and installation of new Simplified Head Assemblies.[4] In addition to the SAFETY improvements recognized by these projects, completion of these projects will lead to higher equipment reliability and shorter outages.

Beginning in 2007 when I assembled my new management team, we committed ourselves – in writing – to the mission of SAFELY and efficiently *generating* electricity for the *long term*. Our first priority was then, is now, and will continue to be, SAFETY. As we developed our recovery plans, our emphasis was on restoring safety margins in our equipment and processes. The emphasis on restoring safety margins also helped restore the confidence that our nuclear safety regulator, the NRC, has in the Station. Cost efficiency was clearly a

[4] Even though we installed new Reactor Vessel Heads and new Simplified Head Assemblies in the fall 2010 Unit 3 outage (3R15), this outage was completed in one day less than the U.S. industry average.

consideration during this period of recovery, but we made a conscious decision to manage our activities towards longer term cost goals.

As we entered a period of transition from recovery of safety margin and regulatory margin to more routine operations, we continued to develop and refine cost and outage improvement goals. The Reactor Vessel Head and Simplified Head Assembly projects that I highlighted above, which significantly increased safety margins, will also help reduce outage duration and result in higher capacity factors.

Therefore, while we recognize Liberty's recommendation that "APS should establish a more aggressive goal of achieving at least industry median capacity factors,"[5] these goals were in place as early as the beginning of 2007, have been developed and refined through 2011, and are expected to drive the Station well above industry median performance by 2013. As noted in the Liberty Report, the Station has experienced operational delays pursuant to material projects that have been in process since the 2003 outages: "There was a period of under-performance, starting perhaps in 2003 [but] there are signs that the plant has indeed entered a new period of improved performance. Our review did verify that there are good things happening."[6] Again, large equipment replacements (Steam Generators, Reactor Vessel Heads, and Simplified Head Assemblies) have been completed and the Plant is now in a position to take advantage of the efficiencies provided by these capital expenditures and execute outage schedules that are more aligned with industry median.

---

[5] Benchmarking Study of Arizona Public Service Company's Operations, Cost, and Financial Performance Docket No. E-01345A-08-0172, FINAL REPORT Presented to the Arizona Corporation Commission, Utilities Division, by the Liberty Consulting Group, February 28, 2011 (the "Liberty Report") at Page 17.

[6] Liberty Report at 16.

In addition to the large equipment replacements, we have also been focusing on facility and process improvements that will make our outage work flow more efficient. As a Station that "is in the outage business" two times per year and that will be completing two outages per year for the next 30+ years, we will continue to look at ways to learn from the industry through benchmarking, and learn from our own experience. On May 6, 2011, we completed the Unit 2 spring outage ("2R16") in 34 days. This duration is well shorter than industry median. While we recognize that one success does not mean that we have remediated all of our prior performance challenges, we are confident that we can build on the successes of 2R16 in the future and will continue the drive to consistently complete routine refueling outages in less than 30 days.

IV. COST EFFICIENCIES AT THE NUCLEAR PLANT.

Q. WHAT IS THE PALO VERDE APPROACH TO EFFICIENT COST MANAGEMENT?

A. The goal of cost efficiency, as stated in the Station mission statement, focuses on SAFELY and efficiently *generating* electricity for the *long term*. Cost analysis is taken very seriously to ensure that the Plant continues to operate safely while associated expenditures (capital projects and budget forecasting) are managed appropriately. The Liberty Report recognizes our position wherein the consultants state "[w]e have considerable experience in cost management approaches, particularly at nuclear plants, and we found the Palo Verde material...to be as good as we have seen[;] the recent cost decreases suggest something positive is underway."[7]

Palo Verde utilizes a variety of measures to ensure costs are managed appropriately, including benchmarking peer nuclear facilities, developing our

[7] Liberty Report at 20.

leaders' business acumen, and using strategic methods such as Top 10 and Long Range Planning processes to prioritize capital projects. For example, the Long Range Planning program provides guidelines to systematically plan for major projects including Plant modifications, major maintenance activities and projects. This allows the Station to anticipate and schedule the required work and related activities to reduce cost. Effective long range planning increases equipment reliability, tracks major projects and component replacements, improves outage performance and manages future budgets and resources which provide a planned response to technical issues before they occur. Variance reports are prepared each month and are reviewed by Palo Verde management and the owners. During outages Palo Verde holds daily budget review meetings with leaders to monitor expenses.

In addition, capital projects are vetted through a multi-tiered process with approvals being required internally at the Station and unanimously by the Participant Owners. First, a project's justification is documented in a business case or work authorization. The process of review and approval of capital modifications is designed to ensure that proposed projects undergo several layers of scrutiny and review to demonstrate they are necessary and reasonable. Plant modifications that will gain safety margin and increase plant reliability, such as the high pressure safety injection and the instrument air modifications, are prioritized to support SAFE and efficient *generation* for the *long term*. Review and approval of capital projects is required by both management and all Participant Owners to ensure that capital improvements at Palo Verde are consistent with the needs of all the Owners and are in the interest of their customers. Lower cost work authorizations are approved by the Engineering and Operating Committee, whose Chair is the Palo Verde Senior Vice President of

Operations, while higher cost work authorizations require Administrative Committee approval, of which I am the Chair.

Cost effectiveness efforts also focus on budget development and control. Budget assumptions, such as staffing, timing, and duration of outages, are established by the Business Operations Department after working with other key groups at the Station. This allows individual functional areas to identify necessary work and begin the process of assembling their budgets. Thereafter, a series of meetings are held by leaders and executives to review the scope and proposed budget amounts and then they are submitted to the Participant Owners.

Once the budget is unanimously approved by the Participant Owners, status is managed by Station leaders and the Business Operations Department. Furthermore, to remain current on status and emergent work, Business Operations analysts regularly interface with functional leaders to monitor and assist in the oversight of costs throughout the year. This oversight includes a review and challenge of costs, cost accruals, cash flow forecasts, contract services, contract labor, staffing, and overtime. The leaders and analysts also meet with senior management to address further challenges, trends, and goals, including where budget under runs can be shared to offset budget overages from one Department to the next.

Monthly Executive Cost Reports are provided to the Participant Owners detailing all aspects of the budget. Furthermore, during outages, Business Operations personnel monitor and challenge costs with Daily Status Reports that are shared with and reviewed by department leaders.

Q. PLEASE EXPLAIN THE COST TO GENERATE NUCLEAR POWER.

A. The cost of electricity generation consists of several components: operations and maintenance costs (such as labor, contractor services, licensing fees, security, materials and supplies, and planned maintenance), and construction costs (procurement and installation of capital equipment). Fuel is also a cost incurred in generation of electricity, but is not included in this testimony because it is included in the Power Supply Adjustor testimony (addressed by APS witness Peter Ewen).

OPERATIONS & MAINTENANCE COSTS. O&M expenses represent the costs required to operate equipment or facilities from day-to-day or maintain equipment and facilities in good operating condition. Palo Verde manages O&M costs through a variety of initiatives. Examples of those initiatives are:

- The Station is utilizing strategic alliances when selecting vendors for contracting services and material purchases (e.g., the Strategic Teaming and Resource Sharing ("STARS") alliance). Membership in STARS provides a fleet-like advantage to seven independently operated nuclear power plants located in the western United States. The result of the alliance is reduced costs and improved performance.

- The Station is also focusing on achieving shorter refueling outages, which reduces the amount of time that outage contractors are needed and increases net generation.

- Palo Verde also implemented a new company wide APS overtime policy on January 1, 2011 to manage exempt employee overtime and reduce expenses.

The Liberty report states that "APS should incorporate into its cost management program, an ongoing analysis of its cost performance versus other [Electric Utility Cost Group] companies,"[8] Palo Verde's long term view since early 2007 has been to reach well into the second quartile and strive to reach first quartile of Electric Utility Cost Group plants. We will continue to use benchmarking as a means to continuously improve performance, in all areas, including cost management. Of course, that needs to be balanced with the primary focus on maintaining a wide safety margin. The Palo Verde 2010 O&M Expenses are described below.

LABOR. Labor costs include both direct and contract employee expenditures to support and balance Plant requirements, overtime, and other related spend such as payroll taxes, benefits, and pensions. Furthermore, and as already addressed, Palo Verde is faced with an aging workforce, which presents additional costs associated with recruiting, hiring, and training replacement employees. To address the costs associated with the engagement of contractors, Palo Verde is implementing a rigorous contractor management system.

MATERIALS AND SUPPLIES. Material costs include items such as Plant equipment, tools, chemicals, protective clothing, and office expenditures. The most significant impact on Palo Verde's budget in this area has been the increasing commodity prices associated with the chemicals needed for water production at the Station. The spike in cost is due to the increase in oil prices used in the production of these products as well as for transportation and delivery of the materials to the Plant. Other material costs have been impacted by the Plant's aging equipment, facilities, and infrastructure as Palo Verde is in

[8] Liberty Report at 22.

its twenty-fifth year of operation. Palo Verde has initiated a Station wide focus to develop synergies with the APS corporate and STARS supply chains. Performance teams and a multi-organizational task force have been established and long range planning and life cycle management is under evaluation to identify material and supplies and when they will be needed.

Finally, as already discussed, Palo Verde is the only nuclear power plants in the United States that that has its own Water Reclamation Facility. Operation of the WRF represents approximately $43 million in annual O&M costs and long-term capital additions and improvements that are not incurred by other nuclear power plants.

FUEL MANAGEMENT AND DECOMMISSIONING COSTS.

REFUELING OUTAGES. The most significant capital spending costs incurred by a nuclear power plant are those affiliated with outages. While refueling outages represent a significant opportunity to boost performance and play a major role in nuclear fleet economics, INPO ratings, and ALARA levels, the cost is substantial. Indeed, outages absorb approximately 8.8% of the total O&M budget and the direct costs can exceed $600,000 per day with additional lost margins for time off-line exceeding $900,000 per day.

During a typical refueling, approximately one-third of the fuel (approximately 100 fuel assemblies) is replaced with fresh unirradiated fuel. In addition, major projects, routine maintenance, testing, and inspections are performed during the outage.

Palo Verde conducts a refueling outage every six months and will continue to do so throughout the life of the Plant. We stress the importance of schedule

adherence since it can significantly affect risk, nuclear safety, and production. Since refueling outages are such an important element of our business, we must achieve excellence in refueling outage performance and the key to outage execution is preparation. At Palo Verde, every employee has three jobs: a day-to-day job, an outage job, and an emergency preparedness job. We approach our outage role with even more skill and care than our day-to-day job because refueling outages are intense. As such, we are shortening the length of outages. As an example, the Reactor Vessel Head replacement outages completed in Unit 2 in 2009 and Units 1 and 3 in 2010 saw a reduction of 20% and 28% respectively from one identical outage to the next.

Q. HOW DOES PALO VERDE PLAN TO MANAGE COSTS GOING FORWARD?

A. Palo Verde will maintain equipment in excellent condition for the long term. Furthermore, we will continue to take a strategic view of costs and invest in people and the Plant to maintain knowledge, performance, and excellent material condition. Although Palo Verde is a low-cost generator of electricity, as a multi-unit fleet, the Station must maintain appropriate levels of resources with adequate margins to ensure excellent and efficient Station operation for the long term.

Q. WHAT ARE THE MOST SIGNIFICANT RISKS CURRENTLY FACING THE PALO VERDE NUCLEAR GENERATING STATION?

A. Absolute standards of SAFETY are sought by not only Palo Verde, but the nuclear industry at large. The setting and enforcement of acceptable risk levels is a matter of public policy and is mandated by various regulatory agencies. Key risks facing Palo Verde include Personnel, Security, Technical Issues, Owner Nuclear Acumen, Public Confidence, and Regulation.

PERSONNEL. The first risk is the loss of knowledge and experience due to retirement or job opportunities at other nuclear utilities, including domestic and

international plants. In response to this challenge, Palo Verde is working to recruit and develop talent, drive performance excellence and model attitudes and behaviors for success. Comprehensive hiring and talent management strategies are being implemented for long-term retention and growth. The hiring model discussed previously reflects the Station's acknowledgement that turnover will occur and efforts to enlist the right people at the right levels of the organization is an immediate necessity.

SECURITY. The second risk is an international or domestic event related to security (physical or cyber) that would impact public confidence and result in additional regulations, ultimately requiring additional funding to enhance security measures. Furthermore, as additional international nuclear plants are constructed, the associated risk of a significant event that could impact Palo Verde grows. Costs in this area are projected to increase as Palo Verde responds to additional NRC mandated security regulations to strengthen the Station's security.

TECHNICAL ISSUES. The third risk is the identification of technical issues that would require additional funding to comply with regulations. Some examples are listed below:

- An equipment/system issue found in one unit that is "transportable" could impact operation of all three units. Sufficient margin is needed to minimize this risk. The equipment reliability program addresses this issue with identification of equipment that could lead to the single point of failure (shut down the plant if it failed) and adjusting preventive maintenance schedules to ensure it remains operable.

- Aging/obsolescent equipment that could impact Plant operation if equipment failed and a replacement could not be located expeditiously

because it is obsolete. Nevertheless, the Plant addresses this issue prior to the equipment failure and/or it becoming antiquated.

- Underground/buried piping is a recent area of regulatory emphasis for Palo Verde and the industry. Industry events at the Vermont Yankee, Oyster Creek, Indian Point, Braidwood, Salem, and other nuclear plants have significantly heightened NRC concerns on buried piping. The Nuclear Energy Institute and the NRC have embarked on a comprehensive buried piping initiative to address these concerns. During the summer of 2010, Palo Verde implemented a new underground piping program that will be fully implemented by the end of 2013.

- International growth and the availability of key spare equipment is another issue facing Palo Verde and the industry. There are a limited number of nuclear industry vendors and their capacity to respond to requests for key spare equipment could be challenged by the demands of the growing international nuclear industry. Again, Palo Verde takes a proactive approach to this issue by identifying key equipment and working with suppliers to ensure its availability prior to equipment failure.

Furthermore, the recent tragic natural disasters in Japan and their impact on the Fukushima Daiichi nuclear plant are not yet fully understood. Palo Verde and the U.S. nuclear industry have taken prompt aggressive actions to evaluate the events at Fukushima Daiichi for potential consequence at Palo Verde and the U.S. nuclear industry, respectively. I can not speculate on the long term impact of those events on the U.S. nuclear power industry but I do expect that regulatory changes to address beyond design basis events may occur in the next few years.

OWNER NUCLEAR ACUMEN. The fourth risk is nuclear acumen of the Participant Owners, which could ultimately impact decision making on necessary improvements that have a financial impact on them. Actions taken to address this issue include development of corporate/owner training programs and additional regular updates by me or the Station Vice Presidents.

PUBLIC CONFIDENCE. The fifth risk is the potential for public confidence issues resulting from an international or domestic event at a nuclear power plant. Again, the natural disaster at the Fukushima Daiichi nuclear power plant is a prime example. Actions taken to address this issue include education of the public, media outreach, and rigorous communication. In 2010, Palo Verde escorted more than 1,500 people through the Plant, including U.S. Senator John McCain, U.S. Representative Trent Franks, NRC Executive Director of Operations R. William Borchardt, Environmental Protection Agency Regional Administrator Jared Blumenfeld, and other local stakeholders. We also assist with community and educational outreach programs focused on raising awareness of the benefits of nuclear power technology.

REGULATORY. Regulatory issues, the sixth risk, could ensue if the Station has degraded performance that impacts regulatory margin or Reactor Oversight Process ranking. Of course, the regulatory mandates would drive additional expenses. Actions taken to address this risk include participation in industry organizations, leader training on the regulatory process, employing key Station personnel who have credibility with the regulatory agencies, use of Station oversight groups with extensive regulatory knowledge, and maintaining formal, informal, and repetitive communications with regulatory agencies.

Q. WHAT MAJOR CAPITAL PROJECTS WERE PLACED INTO SERVICE DURING THE TEST YEAR (2010)?

A. The Station has focused on long term performance and replaced aging Plant components to ensure it continues to can run SAFELY and reliably for the *long term*. In 2010, the total plant capital projects that were placed in service cost approximately $235.7 million. Those projects with a total cost of $10 million or greater, some of which were mandated by regulatory agencies, include the following:

Project ID	Title	Actual In-Service Date	Total PVNGS In Service in 2010 (in thousands)	APS Share In Service in 2010 Estimate (in thousands)
070075	Simplified Head Assembly U-1	5/23/2010	$32,995	$9,602
070077	Simplified Head Assembly U-3	11/10/2010	$30,202	$8,789
050081	Rx Vessel Head Repl., U3	11/10/2010	$28,603	$8,324
050080	Rx Vessel Head Repl., U1	5/23/2010	$22,887	$6,660
100112	Circulating Water Tie-In U3	11/10/2010	$11,975	$3,485
090210	Security Prescreening Facility (PASE)	11/29/2010	$10,601	$3,085

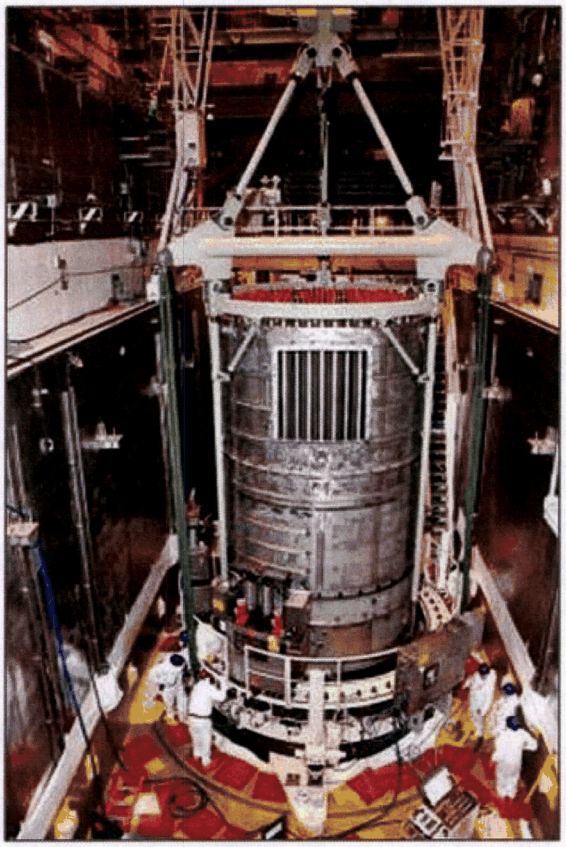
Replacement of the Reactor Vessel Heads and installation of Simplified Head Assemblies were successfully completed on Unit 2 in 2009 and Units 1 and 3 in 2010. Initially, the industry used Reactor Vessel Heads with the alloy Inconel 600; however, in recent years the Inconel 690 alloy, which is more resistant to stress corrosion cracking, has become the material of choice for applications susceptible to stress corrosion cracking. The Station installed Reactor Vessel Heads containing Inconel 690, which has improved the nuclear safety margin, eliminated Inconel 600 material welds and nozzles, and will ultimately reduce outage costs associated with the aging Reactor Vessel Heads. Additionally, the new Reactor Vessel Heads will also provide a single failure proof Reactor Vessel Head lift rig that will reduce the time to complete outage destack and restack.

Shorter outages translate into higher capacity factors for the Station and lower cost for the ratepayer. Photos of Reactor Vessel Head work are provided below.

ARRIVAL OF NEW REACTOR VESSEL HEAD AT THE STATION

LIFT OF REACTOR VESSEL HEAD INTO CONTAINMENT

REACTOR VESSEL HEAD SET ON REACTOR VESSEL



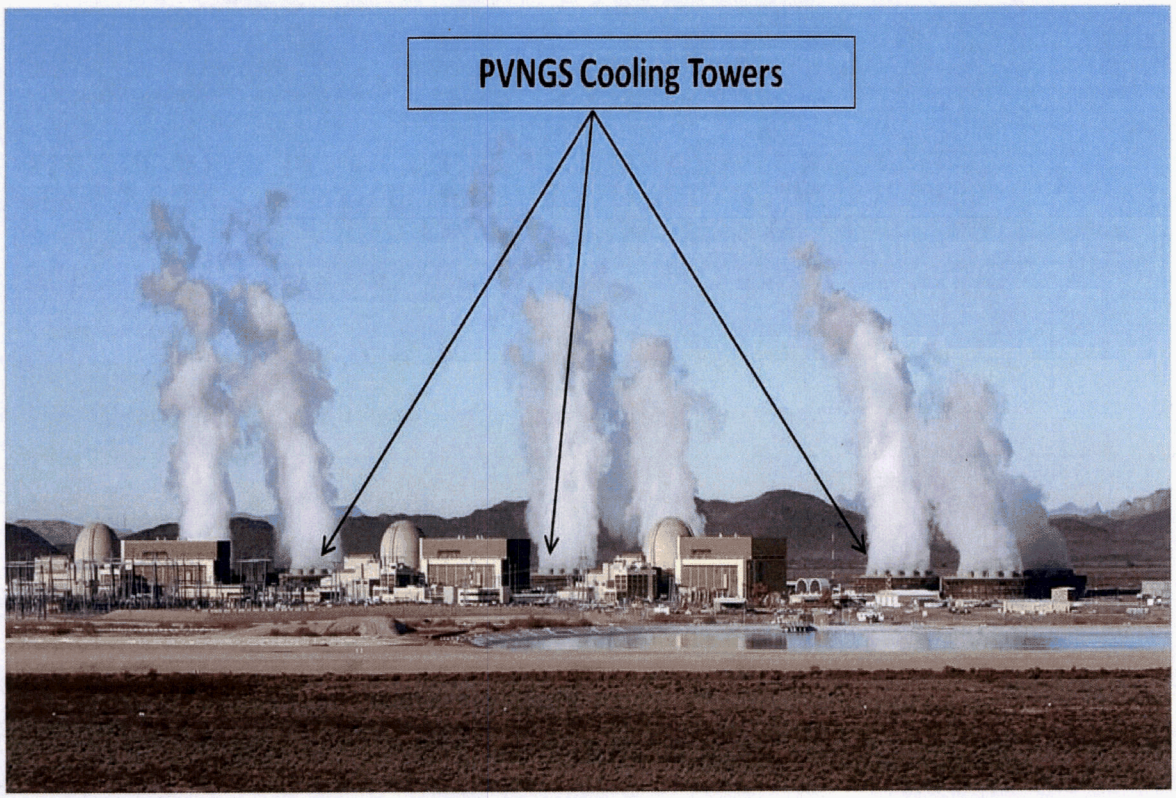
Simplified Head Assemblies that were installed during the 2009 and 2010 outages will provide significant improvements in safety margins. With respect to nuclear safety, the new Simplified Head Assemblies reduce utilization for the polar crane from approximately 24 manipulations to 6 manipulations. Therefore, fewer and shorter lifts of heavy components over the reactor vessel reduces the potential for an accident that might damage the reactor core. The reduced number of lifts also minimizes the amount of manual labor by maintenance personnel, therefore resulting in reduced potential for industrial safety incidents. The Simplified Head Assemblies also contain permanent upper and lower Reactor Vessel Head radiation shielding shrouds, thus eliminating the requirement to install and remove Reactor Vessel Head temporary shielding during refueling outages, which reduces potential worker exposure to high

radiation environments and maintaining exposure ALARA. Photos of Simplified Head Assembly work are provided below.

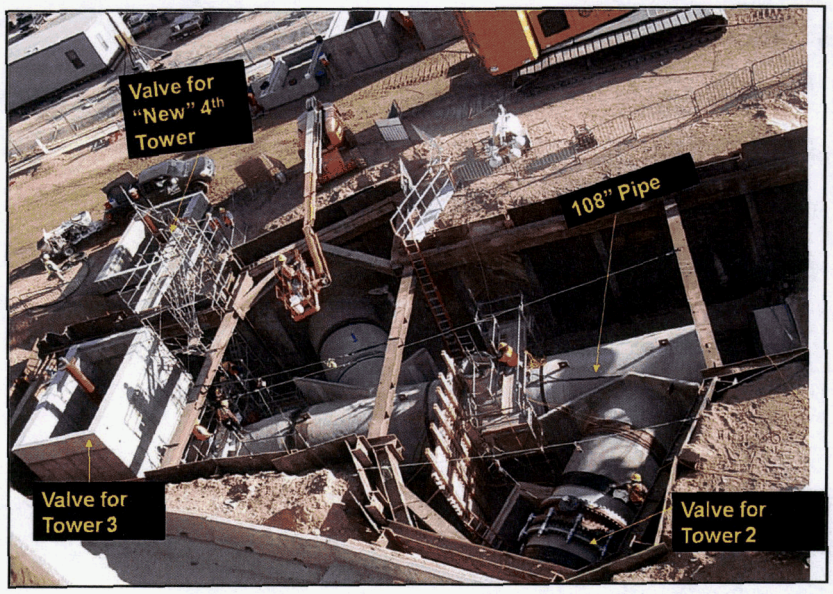
ORIGINAL REACTOR VESSEL HEAD ASSEMBLY

NEW SIMPLIFIED HEAD ASSEMBLY

In the table above that lists those projects with a total cost of $10 million or greater that were placed into service in 2010, we identified cooling tower replacement tie-ins for Units 1 and 3. The cooling tower tie-in project involved the installation of a branch connection and butterfly valves into the piping that returns water from the unit condensers to the cooling towers. The tie-in provides the option of isolating a tower and keeping the other two towers in operation if repairs are needed or if cooling tower replacement is necessary. Photos of the cooling tower tie-in work are provided below.



COOLING TOWER TIE-IN WORK



Q. WHAT NUCLEAR PROJECTS DOES APS PLAN ON PUTTING IN SERVICE BETWEEN THE END OF TEST YEAR 2010 AND JULY 1, 2012 (POST TEST YEAR)? PLEASE INCLUDE THE COST.

A. The total cost of Palo Verde projects that APS plans to place in service in the Post Test Year period is $412.7 million. The APS share of this is $120.1 million. The projects that are projected to exceed a total Palo Verde cost of $10 million are listed below.

Projects Projected In Service from January 1, 2011 through June 30, 2012			
Project ID	**Post Test Year Project Titles**	**Palo Verde Projected Cost (in thousands)**	**APS Projected Closed Cost (in thousands)**
070005	WRF Evap. Pond #2 Liner Replacement	$89,127	$25,936
060066	Component Design Basis Review	$41,174	$11,982
080080	Outage Support Facility	$31,627	$9,204
040051	Plant Aging Management Project	$25,468	$7,411
100040	Emergency Operations Facility	$16,490	$4,799
090076	Security Fence Extension Plant West	$13,862	$4,034
090075	Power Expansion Plant West	$12,540	$3,649
080153	North Annex Building Upgrades	$12,010	$3,495
090126	Upgrade Ingress/Egress Road	$10,849	$3,157
100087	TF/FC Sump Life Extensions	$10,468	$3,046

Q. BRIEFLY DESCRIBE THE PROJECTS DESRBED IN THE PRECEDING TABLE.

A. The following contains information regarding the individual projects discussed above.

- **WRF Evaporation Pond #2 Liner Replacement.** The purpose of this project is design and construction of replacement embankments for Evaporation Pond #2, as well as replacement of the pond's liner. The existing liner system has reached the end of its useful life and is experiencing increased degradation. The embankments need to be rebuilt because they have experienced cracking. The evaporation ponds are a critical component of the site's water management system.

- **Component Design Basis Review.** This project will review and replace inaccurate components of the Component Design Basis Manual ("CDBM"). The CDBM includes drawings and calculations, and other plant specifications relating to the various systems within the plant. It is critical that this information be correct as it is used by the NRC to ensure that the plant is operating within design specifications. The site made a commitment to the NRC that it would review all of the documents and revise them to accurately reflect design basis requirements.

- **Outage Support Facility**. This project will consolidate all of the outage related functions into one area to improve the efficiency of both outage planning and execution. Currently outage planning and preparation activities are performed in various areas of the plant and must often compete with on-going operational activities for use of space and equipment. Completion of this project will result in better communication

and coordination among the groups responsible for the outage, more efficiently run outages and reduced cost.

- **Plant Aging Management Project**. The purpose of this project is to conduct engineering reviews necessary to identify equipment aging management issues across the site and to support activities necessary to submit the site's license renewal application. Successful completion of this project will result in an extension of the site's operating license from the NRC for an additional 20 years of operation from 2026 to 2046.

- **Emergency Operations Facility**. This project involves the construction of an off-site emergency operations facility to be used as a "nerve center" for site operations in case of an emergency situation. Pending NRC 10CFR50.47 rule changes require licensees to maintain an offsite facility capable of performing functions required to respond to an event. The functions specified in Federal Register Vol. 74, No 94 include classification, notification, and issuance of protective action recommendations and development of mitigation strategies using plant computer system information. This requires replacement of the existing facility outside a 10 mile but within a 25 mile range of the site. The State of Arizona currently owns the Joint Information Center. Co-locating the JIC and the EOF restores control of the JIC to Palo Verde which, in turn, will ensure compliance with regulatory requirements.

- **Security Fence Extension Plant West**. This project is to construct a fence to incorporate the expanded west side of the site into the Protected Area (PA). The site is constructing several new facilities on the west side of the plant in an area currently not encompassed by the Protected Area fence.

After these facilities are completed, the fence will be extended to include them in the Protected area to improve plant safety and security as well as efficiency. The facilities to be incorporated into the new PA are the Outage Support Facility, the new Warehouse inside the PA, the Vehicle Minor Maintenance Facility and the Fuel Depot.

- **Power Expansion Plant West**. This project will install a new 100 MVA transformer to provide site-generated power to the planned west side expansion of the site. The site is planning to expand the Protected Area to the plant west of the existing PA. This expanded area will house the new Outage Support Facility and the new Warehouse inside the PA as well as several other new installations planned for the next several years. Sufficient metered power is not available at present to power the new installations. Economic analysis of options demonstrates that using site-power for these loads is the superior economic choice. Site-power is also preferable from a reliability perspective.

- **North Annex Builiding Upgrades**. This project is to renovate an existing administrative building on site to resolve numerous building code violations and to make the space more efficient for continued use. The building is original to the site and has not been upgraded in 30 years. This building is critical to the Site Master Facility Plan execution as it is planned for swing space as other areas on site are remodeled to increase their efficient use of space. The option of remodeling is approximately 2/3 the cost of construction of a new building and is, therefore, the more financially feasible solution.

- **Upgrade Ingress/Egress Road**. The purpose of this project is to construct a new ingress/egress road, expand the parking lot "C", and reconfigure the Security Owner Controlled Area (SOCA). These improvements will significantly reduce, if not eliminate, traffic backing up into Wintersburg Road, especially during outages when there are a large number of contractors entering the site which will improve safety for both drivers entering the plant and other traffic on Wintersburg Road. The SOCA reconfiguration will improve site safety and security by eliminating parking for personal vehicles inside the SOCA. Personnel will park in Lot "C" and enter through a security entrance where biometric scanners will permit only those persons with authorized access to enter. The project will result in a reduction of required Security Officers. An economic analysis of the project returned a positive net present value and an internal rate of return of 13%.

- **TF/FC Sump Life Extensions**. This project replaces sections of degraded concrete and reinforcing steel of the large sump structure that takes in water from the trickling filters and clarifier filters. All water flowing into the water reclamation facility goes through this structure which has degraded due to corrosion of the concrete and reinforcing steel from chloride attack from the influent.

Q. WHICH OF THESE PROJECTS DOES APS REQUEST TO BE INCLUDED AS PRO FORMA ADJUSTMENTS TO THE TEST YEAR? ALSO, DOES APS SEEK TO INCLUDE ANY OTHER PRO FORMA ADJUSTMENTS TO THE TEST YEAR RELATING TO PALO VERDE?

A. APS requests that all of the projects be included as pro forma adjustments. However, after considering higher levels of depreciation reserves and accumulated deferred taxes, there will be a net reduction of $5.2 million to APS's Total Company cost rate base attributable to Palo Verde. This adjustment can be

found on SFR Schedule B-2, page 2, column 5. APS witness Jason La Benz speaks to the details of this adjustment, including the related impacts of property taxes, depreciation and interest.

Q. WHAT TOTAL ADJUSTMENT TO THE TEST YEAR IS APS PROPOSING TO INCLUDE FOR CAPITAL EXPENDITURES RELATED TO PALO VERDE?

A. The gross plant adjustment for APS is $120.1 million. This is the projected total related to work orders that will be placed in service from January 1, 2011 to June 30, 2012. Please see Attachment RKE-1 for a complete listing of the projects included in the adjustment.

Q. IS THERE ADDITIONAL INFORMATION YOU WOULD LIKE TO ADD ABOUT PALO VERDE?

A. Yes. In the middle of 2010, Palo Verde released the results of an economic impact study (the "Applied Economics" report) that it had performed to evaluate the impact of Palo Verde on the regional economy. The Applied Economic report concluded that Palo Verde creates an annual economic impact of approximately $1.8 billion on the Arizona economy. In total, Palo Verde directly and indirectly supports an estimated 8,800 jobs and $508.8 million in annual payroll in Arizona. Palo Verde directly provided about 2,900 "recession-resistant" jobs for employees and contractors with a combined payroll of $255.1 million annually in 2009. An additional 5,800 jobs and $253.7 million in payroll are supported annually at other businesses throughout the state through the economic multiplier effect. Included in the economic impact cited above is a twice-per-year "surge" of several hundred non-local temporary workers who spend substantial sums on lodging and food while in the area to support Palo Verde's 30- to 60-day refueling outages. Due to the transient nature of these non-

local contractors, a substantial number of them reside in local hotels, eat at local restaurants, and utilize other local service industry businesses.

Annual property tax revenues from Palo Verde are estimated at $50 million per year, and state, county and city sales taxes are estimated at an average of $54.7 million per year. Palo Verde also generates substantial indirect property, sales and income tax revenues in Arizona through employee spending and property ownership. Indirect revenues are estimated at an average of $13.8 million per year.

The Station made an estimated $223.8 million in local purchases for various equipment, supplies and services in 2009. Based on the share of vendor purchases that are made locally, the annual economic impact on the state was estimated at $399.4 million in 2009.

When Palo Verde workers retire, the majority remain in the area. They provide a positive economic impact of $4.7 million annually, and an increasing number of workers at Palo Verde will reach retirement age over the next three to five years.

A number of national nuclear utility vendor companies have established offices in the West Valley as a direct result of their relationship with Palo Verde — and others are being actively encouraged to establish local branch offices here. While these offices were initially established to serve Palo Verde and the STARS alliance, some are now serving other local and non-local customers — and some have plans for expansion. The economic impact of expansions related to companies growing their customer base is in addition to the positive economic impacts detailed in the Applied Economics report.

The economic impact study did not consider the economic impact of the reliable and affordable energy produced by Palo Verde. In other words, the economic impact study did not take into account the affordably-priced electricity produced at Palo Verde that may entice an expanding business to move its operations to Arizona or encourage a potential homeowner looking for place to settle to consider Arizona as the residence destination of choice.

The impact of rates on APS's customers certainly is an important consideration. But it is also important to recognize that Palo Verde has broader impacts that are not reflected in rates as it is a significant and substantial economic engine for the state of Arizona. And, given the joint ownership model, much of that impact to Arizona results from rates paid by customers in California, New Mexico and Texas.

V. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS TO YOUR DIRECT TESTIMONY?

A. As I stated at the outset of my testimony, the mission of Palo Verde is to SAFELY and efficiently *generate* electricity for the *long term*. Our responsibility as stewards of the ratepayers' and other stakeholders' investment is shaped by one certainty: SAFETY. Our responsibility as the NRC's licensee for the operation of Palo Verde is to protect public health, safety, and the environment. I demand the overriding SAFETY priority from every employee.

While SAFELY and efficiently *generating* electricity at Palo Verde over the past several years, we have had some notable achievements:

- Not only was Palo Verde the first and only generating site in the United States to ever produce more than 31 million megawatt-hours in a single

year, the Station has exceeded 30 million megawatt-hours in a single year on six occasions. Furthermore, no other U.S. generating station (of any fuel type) has ever produced 30 million megawatt-hours.

- Unit 2 was the world's top electricity generator in 2010 and Unit 1 was the top generator in 2009.

- All three units at Palo Verde operated simultaneously throughout the 2010 summer until the Unit 3 fall outage. Moreover, for three straight years, the three units have operated continuously for at least 100 days during triple-digit temperatures throughout the summer providing safe reliable power to APS customers.

- In 2009, our operations had an overall economic impact on Arizona of $1.8 billion and our annual projections show similar impacts through 2013.

With the major equipment upgrades completed over the past few years, the completion of a long-term cooling water agreement, and NRC's recent approval of Palo Verde's license renewal application, Palo Verde is positioned to provide safe, reliable and efficient production of electricity and continue to be an economic engine for Arizona through the middle of this century.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
1.	070005	WRF Evap Pond #2 Liner Replacement	The purpose of this project is design and construction of replacement embankments for Evaporation Pond #2, as well as replacement of the pond's liner. The existing liner system has reached the end of its useful life and is experiencing increased degradation. The embankments need to be rebuilt because they have experienced cracking. The evaporation ponds are a critical component of the site's water management system.	$ 21,030,283	$ 4,905,782	$ 25,936,065	1/31/2012
2.	060066	Component Design Basis Review	The purpose of this project is to review and replace inaccurate components of the Component Design Basis Manual (CDBM). The CDBM includes drawings and calculations, and other plant specifications relating to the various systems within the plant. It is critical that this information be correct as it is used by the NRC to ensure that the plant is operating within design specifications. The site made a commitment to the NRC that it would review all of the documents and revise them to accurately reflect design basis requirements.	$ 9,967,411	$ 2,014,206	$ 11,981,617	12/30/2011
3.	080080	Outage Support Facility	The purpose of this project is to consolidate all of the outage related functions into one area to improve the efficiency of both outage planning and execution. Currently outage planning and preparation activities are performed in various areas of the plant and must often compete with on-going operational activities for use of space and equipment. Completion of this project will result in better communication and coordination among the groups responsible for the outage, more efficiently run outages and reduced cost.	$ 2,353,797	$ 6,849,743	$ 9,203,540	4/30/2012
4.	040051	Plant Aging Management Project	The purpose of this project is to conduct engineering reviews necessary to identify equipment aging management issues across the site and to support activities necessary to submit the site's license renewal application. Successful completion of this project will result in an extension of the site's operating license from the NRC for an additional 20 years of operation from 2026 to 2046.	$ 6,882,835	$ 528,385	$ 7,411,220	4/30/2011
5.	100040	Emergency Operations Facility	The purpose of this project is to construct an off-site emergency operations facility to be used as a "nerve center" for site operations in case of an emergency situation. Pending NRC 10CFR50.47 rule changes require licensees to maintain an offsite facility capable of performing functions required to respond to an event. The functions specified in Federal Register Vol. 74, No 94 include classification, notification, and issuance of protective action recommendations and development of mitigation strategies using plant computer system information. This requires replacement of the existing facility outside a 10 mile but within a 25 mile range of the site. The State of Arizona currently owns the Joint Information Center. Co-locating the JIC and the EOF restores control of the JIC to Palo Verde which, in turn, will ensure compliance with regulatory requirements.	$ 3,537,854	$ 1,260,652	$ 4,798,506	6/15/2011
6.	090076	Security Fence Extension Plant West	The purpose of this project is to construct a fence to incorporate the expanded west side of the site into the Protected Area (PA). The site is constructing several new facilities on the west side of the plant in an area currently not encompassed by the Protected Area fence. After these facilities are completed, the fence will be extended to include them in the Protected area to improve plant safety and security as well as efficiency. The facilities to be incorporated into the new PA are the Outage Support Facility, the new Warehouse inside the PA, the Vehicle Minor Maintenance Facility and the Fuel Depot.	$ 368,277	$ 3,665,596	$ 4,033,873	3/12/2012

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
7.	090075	Power Expansion Plant West	The purpose of this project is to install a new 100 MVA transformer to provide site-generated power to the planned west side expansion of the site. The site is planning to expand the Protected Area to the plant west of the existing PA. This expanded area will house the new Outage Support Facility and the new Warehouse inside the PA as well as several other new installations planned for the next several years. Sufficient metered power is not available at present to power the new installations. Economic analysis of options demonstrates that using site-power for these loads is the superior economic choice. Site-power is also preferable from a reliability perspective.	$ 2,904,709	$ 744,499	$ 3,649,208	6/30/2011
8.	080153	North Annex Building Upgrades	The purpose of this project is to renovate an existing administrative building on site to resolve numerous building code violations and to make the space more efficient for continued use. The building is original to the site and has not been upgraded in 30 years. This building is critical to the Site Master Facility Plan execution as it is planned for swing space as other areas on site are remodeled to increase their efficient use of space. The option of remodeling is approximately 2/3 the cost of construction of a new building and is, therefore, the more financially feasible solution.	$ 158,678	$ 3,335,974	$ 3,494,652	12/31/2011
9.	090126	Upgrade Ingress/Egress Road	The purpose of this project is to construct a new ingress/egress road, expand the parking lot "C", and reconfigure the Security Owner Controlled Area (SOCA). These improvements will significantly reduce, if not eliminate, traffic backing up into Wintersburg Rd., especially during outages when there are a large number of contractors entering the site which will improve safety for both drivers entering the plant and other traffic on Wintersburg Rd. The SOCA reconfiguration will improve site safety and security by eliminating parking for personal vehicles inside the SOCA. Personnel will park in Lot "C" and enter through a security entrance where biometric scanners will permit only those persons with authorized access to enter. The project will result in a reduction of required Security Officers. An economic analysis of the project returned a positive net present value and an internal rate of return of 13%.	$ 537,683	$ 2,619,439	$ 3,157,122	9/15/2011
10.	100087	TF/FC Sump Life Extension	The purpose of this project is to replace sections of degraded concrete and reinforcing steel of the large sump structure that takes in water from the trickling filters and clarifier filters. All water flowing into the water reclamation facility goes through this structure which has degraded due to corrosion of the concrete and reinforcing steel from chloride attack from the influent.	$ 1,493,160	$ 1,552,908	$ 3,046,068	11/1/2011
11.	120016	CT Life Extension U3 2012	The purpose of this project is replacement of Unit 3 cooling tower structural components (distribution deck sections and fill support beams), fill material, and fan assemblies in the cooling towers to improve their operational efficiency and structural integrity. This work is necessary because the cooling towers are continuously exposed to aggressive chemicals in circulating water, degrading concrete components due to corrosion of the reinforcing steel. This work will extend the useful lives of the cooling towers.	$ -	$ 2,881,064	$ 2,881,064	4/1/2012

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
12.	070008	TF Rehabilitation	The purpose of this project is to rebuild one of the site's six trickling filters (TFs) that are used in the process of purifying the influent piped into the plant for the cooling water used to remove excess heat from the Units . The TFs remove ammonia from the influent, reducing the amount of chemicals used in the downstream treatment process. Over time, the structure, machinery & equipment, and plastic media of the TFs have been degraded due to the corrosive action of the influent. Included in the work scope is replacement of fiberglass side walls and the plastic media, as well as refurbishment of machinery and concrete structural components.	$ 2,735,074	$ 42,184	$ 2,777,258	2/11/2011
13.	110021	CT Life Extension U2 2011	The purpose of this project is replacement of Unit 2 cooling tower structural components (distribution deck sections and fill support beams), fill material, and fan assemblies in the cooling towers to improve their operational efficiency and structural integrity. This work is necessary because the cooling towers are continuously exposed to aggressive chemicals in circulating water, degrading concrete components due to corrosion of the reinforcing steel. This work will extend the useful lives of the cooling towers.	$ -	$ 2,708,648	$ 2,708,648	5/31/2011
14.	110020	CT Life Extension U1 2011	The purpose of this project is replacement of Unit 1 cooling tower structural components (distribution deck sections and fill support beams), fill material, and fan assemblies in the cooling towers to improve their operational efficiency and structural integrity. This work is necessary because the cooling towers are continuously exposed to aggressive chemicals in circulating water, degrading concrete components due to corrosion of the reinforcing steel. This work will extend the useful lives of the cooling towers.	$ -	$ 2,442,238	$ 2,442,238	11/15/2011
15.	090011	PBX Replacement	The purpose of this project is replacement of the site's PBX switches and associated telephone network hardware and software. Being replaced with two modern PBX switches and associated software are three old PBX switches installed before 1990 that are obsolete and are no longer supported by the original vendor. The project incorporates recommendations from a comprehensive study performed in 2008 that evaluated all of the PV's communication infrastructure, including: 1) migration from analog telephones to digital telephones using Voice over Internet Protocol (VoIP) for all office environments at the site, and 2) migration from an obsolete, unstable Octel voicemail system to a state-of-the-art Cisco unified voicemail messaging system.	$ 1,356,705	$ 562,856	$ 1,919,561	8/31/2011
16.	090217	2009 Security Fencing	The purpose of this project is to address site defense vulnerabilities identified in self-assessments performed prior to the 2010 Nuclear Regulatory Commission Force-on-Force evaluation and subsequently in response to the evaluation. Additional, more detailed information is considered Safeguards.	$ 1,866,022	$ 47,695	$ 1,913,717	3/15/2011
17.	070024	Main Generator Rotor Rewind U1	The purpose of this project is to install the refurbished Main Generator Rotor into Unit 1 as part of the Long Range Plan (LRP). A Main Generator LRP has been developed to systematically refurbish / rewind the three Main Generator Rotors to address aging electrical insulating condition, and promote reliable operation.	$ 1,626,345	$ 176,671	$ 1,803,016	5/15/2011

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
18.	080092	Main Transformer Rewind (from U1R14)	The purpose of this WA is the rebuild of the main transformer as part of the LRP, including the complete rewind of the phase using copper conductor and insulating material. All internal wiring will be inspected and replaced as necessary. The expected end of life for a main transformer is 30-40 years. A Large Power Transformer LRP has been developed to systematically replace and refurbish PVNGS' Generator Step Up transformer to address aging electrical insulating condition, and promote reliable operation.	$ 1,419,039	$ 181,820	$ 1,600,859	3/28/2011
19.	110107	WRSS Pipeline - 2011 Scope	The purpose of this project is continuation of the pipe rebuilding program started in 1999 to deal with widespread corrosion on the water reclamation supply system (WRSS) pipeline that runs from the Phoenix sewage treatment facility to the WRF. The concrete pipe spools in the 39 mile underground line are under attack from the chemicals in the influent from the sewage treatment facility. Failures of the WRSS pipeline could severely impact operations of all three PVNGS units and could have an adverse impact on the environment and regulatory margin. Therefore, rebuilding of the degraded spools is necessary for continuous, event-free operation of the plant.	$ -	$ 1,398,894	$ 1,398,894	11/15/2011
20.	090148	Main Transformer Rewind "C" U2R15	The purpose of this project is to rewind the Unit 2 "C" transformer. The expected end of life for a main transformer is 30-40 years. A Large Power Transformer Long Range Plan has been developed to systematically replace and refurbish PVNGS' Generator Step Up transformer to address aging electrical insulating condition, and promote reliable operation.	$ 334,149	$ 1,003,904	$ 1,338,053	9/15/2011
21.	100239	TB "A" Blowdown Line Pipe replacement	The purpose of this project is replacement of degraded pipes, valves, pipe supports, concrete berms, instrumentation and controls from the 8" nozzle on the circulating water return header in all three units to the evaporation pond inlet valve structure. Also included is excavation of Circulating Water (CW) return line, installation of a new stainless steel riser and installation of an isolation valve above ground with associated support.	$ 135,282	$ 972,305	$ 1,107,587	4/30/2012
22.	090027	Circ Water Pipeline Replacement, Phse III, U2	The scope of this project includes identification and rebuilding of up to 10 sections in each of the Unit 1, Unit 2 and Unit 3 Circulating Water System pipe sections, due to their degraded condition. This water line provides critical water to the plant for operations and degraded pipe impairs the reliability of the water source.	$ -	$ 818,235	$ 818,235	12/31/2011
23.	090131	Cask Load Pit Leak Detection U1	The purpose of this project is to install both a leak detection system and a water level indicator in the cask load pit (CLP) for each unit. These are required to bring the CLPs into compliance with 10CFR50 Appendix A, General Design Criteria 60 & 64, which mandate that the site provides the means to control the release of radioactive materials and monitor such releases. From the plant's inception it has been assumed that the CLPs would not be full often enough to present a risk of leaks and potential radiation exposure. However, due to fuel movements and inspections, reactor loading during outages, and dry storage campaigns, the CLPs are full more than originally anticipated. Therefore, to increase control and monitoring, leak detection systems and water level indicators are being installed in the CLPs.	$ 195,802	$ 601,245	$ 797,047	4/15/2011
24.	080042	2009 PA Evacuation System	The purpose of this project is to replace public address and evacuation system components which are over 21 years old and are experiencing an increasing component failure rate. These systems are required to give instructions to individuals in and around the site in case of an emergency.	$ 764,179	$ 29,813	$ 793,992	2/15/2011

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
25.	090091	Hydrazine Injection Mod - Unit 2	The purpose of this project is to modify the Hydrazine Chemical Addition system to address industry-wide issues related to pump failures. Hydrazine is a chemical which removes dissolved oxygen gas to prolong the life of the steam generators and system piping. Failure to maintain the hydrazine levels results in corrosion and corrosion product transport to steam generators.	$ 321,269	$ 413,534	$ 734,803	5/15/2011
26.	100088	GF/Clearwell Life Extension	The purpose of this project is rebuilding of the Water Reclamation Facility (WRF) gravity filter (GF) clearwell. This concrete and steel structure is substantially degraded from contact with corrosive chemicals in the water. It requires rebuilding and resurfacing to restore structural integrity, to permit continued safe operation, and to extend its life. The Clearwell performs 2 critical functions: 1) moving filtered water from the GF to the water storage reservoirs which supply the units with cooling water, and 2) providing process water for the WRF plant.	$ 394,920	$ 310,435	$ 705,355	12/20/2011
27.	100236	Main Transformer C Replacement -U1	The purpose of this project is to replace the Generator Step-up transformer "C" for Unit 2. The transformer is required to convert the electrical power from the generator to a voltage that can be transmitted to the power grid. The transformer is approaching the end of its useful life and must be replaced to ensure reliable transmission of electricity.	$ -	$ 638,242	$ 638,242	12/31/2011
28.	100126	Boric Acid Concentrator Vent Line Reroute	The purpose of this project is to reroute the Boric Acid Concentrator vent line from its current connection to an HVAC duct directly to an exhaust duct to prevent tritium-laden steam from condensing in the HVAC duct.	$ 26,705	$ 575,488	$ 602,193	3/31/2012
29.	110006	Fixed In-Core Detectors Repl. U2R16	The scope of this project is replacement of depleted in core detectors to ensure accurate measurement of in-core parameters as required by technical specifications. The detectors are located inside the reactor vessel and record various measurements to ensure how the fuel is being used.	$ -	$ 582,573	$ 582,573	5/15/2011
30.	090089	Hydrazine Injection Mod - U1	The purpose of this project is to modify the Hydrazine Chemical Addition system to address industry-wide issues related to pump failures. Hydrazine is a chemical which removes dissolved oxygen gas to prolong the life of the steam generators and system piping. Failure to maintain the hydrazine levels results in corrosion and corrosion product transport to steam generators.	$ 87,724	$ 436,029	$ 523,753	11/15/2011
31.	090090	Hydrazine Injection Mod - Unit 3	The purpose of this project is to modify the Hydrazine Chemical Addition system to address industry-wide issues related to pump failures. Hydrazine is a chemical which removes dissolved oxygen gas to prolong the life of the steam generators and system piping. Failure to maintain the hydrazine levels results in corrosion and corrosion product transport to steam generators.	$ 87,697	$ 435,107	$ 522,804	5/15/2012

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
32.	090132	Cask Load Pit Leak Detection U3	The purpose of this project is to install both a leak detection system and a water level indicator in the cask load pit (CLP) for each unit. These are required to bring the CLPs into compliance with 10CFR50 Appendix A, General Design Criteria 60 & 64, which mandate that the site provides the means to control the release of radioactive materials and monitor such releases. From the plant's inception it has been assumed that the CLPs would not be full often enough to present a risk of leaks and potential radiation exposure. However, due to fuel movements and inspections, reactor loading during outages, and dry storage campaigns, the CLPs are full more than originally anticipated. Therefore, to increase control and monitoring, leak detection systems and water level indicators are being installed in the CLPs.	$ 195,625	$ 286,951	$ 482,576	6/21/2011
33.	080043	Fatigue Rule Software (formerly Employee Time Cap)	The purpose of this project is to acquire and implement software that applies fatigue management rules and work hour controls to nuclear utility workers who direct work or work on safety-related equipment in the access-controlled area. This project is required to comply with the March 2008 issuance by the NRC of 10 CFR Part 26 Fitness for Duty Programs, Final Rule, which requires stringent monitoring of hours worked by affected personnel.	$ 412,435	$ 52,552	$ 464,987	10/15/2011
34.	080073	Cask Load Pit Leak Detection U2	The purpose of this project is to install both a leak detection system and a water level indicator in the cask load pit (CLP) for each unit. These are required to bring the CLPs into compliance with 10CFR50 Appendix A, General Design Criteria 60 & 64, which mandate that the site provides the means to control the release of radioactive materials and monitor such releases. From the plant's inception it has been assumed that the CLPs would not be full often enough to present a risk of leaks and potential radiation exposure. However, due to fuel movements and inspections, reactor loading during outages, and dry storage campaigns, the CLPs are full more than originally anticipated. Therefore, to increase control and monitoring, leak detection systems and water level indicators are being installed in the CLPs.	$ 3,553	$ 458,868	$ 462,421	6/23/2012
35.	090087	Personnel Air Lock (PAL) Mod - Unit 2	This WA includes the design and replacement of all 4 Personal Air Lock (PAL) doors operating mechanisms in Unit 2. The PAL doors allow personnel to enter containment while still maintaining the integrity of the containment dome to control potential radioactive release.	$ 8,160	$ 454,036	$ 462,196	5/7/2011
36.	000030	Rad Monitoring System Monitors	The purpose of this project is replacement of the monitors for the radiation monitoring system at unit 1, due to their age and poor condition. The Radiation Monitoring System (RMS) provides radiation level indication of radiological conditions throughout the plant to the operations staff. The microcomputers function independently to monitor radiation levels, initiate alarms, initiate trips and control sampling (process monitors).	$ 377,253	$ 78,896	$ 456,149	12/15/2011
37.	110101	ISFSI Berm Stabilization	The purpose of this project is to stabilize the existing ISFSI berm and install OSHA approved safety features to improve the safety for workers performing tasks on and near the berm, especially in low-light conditions. The ISFSI berm serves as a radiation shield for dry cask storage of spent nuclear fuel.	$ 308,098	$ 107,131	$ 415,229	1/28/2011
38.	090204	SC-942 Replacement pH/Conductivity Meters U2	The purpose of this replacement is to ensure reliable and accurate pH and conductivity analysis of the Secondary Chemistry (SC) system. All outdated and obsolete pH and conductivity analyzers and associated sensing units will be replaced with state of the art and cost saving multiple channel, multiple function instrumentation and sensors.	$ 241,388	$ 142,719	$ 384,107	5/15/2011

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
39.	090205	SC-942 Replacement pH/Conductivity Meters U3	The purpose of this replacement is to ensure reliable and accurate pH and conductivity analysis of the Secondary Chemistry (SC) system. All outdated and obsolete pH and conductivity analyzers and associated sensing units will be replaced with state of the art and cost saving multiple channel, multiple function instrumentation and sensors.	$ 27,166	$ 353,969	$ 381,135	5/15/2012
40.	100142	Resin Processing Equipment	The scope of this project is to purchase and install new spent resin processing equipment to replace the current equipment that is over 20 years old. It has become unreliable and replacement parts are difficult to procure. The three units use resin in the primary and secondary systems to purify water. Once the resin is expended, it is discharged into liners or high integrity containers for disposal utilizing resin processing equipment to complete this evolution	$ 214,344	$ 162,395	$ 376,739	12/31/2011
41.	110088	Cooling Tower NRQ Circuit Breakers	The purpose of this project is to purchase and install new circuit breakers to replace the existing twenty one cooling tower fan breakers on the cooling towers. The breakers have been utilized in the cooling tower environment for over 20 years and need replacement/refurbishment to ensure safety and equipment reliability. The breaker is designed to isolate a fault and actuate a vibration switch to trip the breaker thereby removing the energy source for the cooling tower fans. Failure of these to operate as expected can cause significant physical damage to the cooling towers.	$ -	$ 369,354	$ 369,354	4/15/2011
42.	080071	RWT Instrumentation System Replacement, U2	The purpose of this project is design and installation of modifications to the Refueling Water Storage System to increase the operating margin of this system by expanding the usable operational volume of the Refueling Water Tanks (RWTs). This increase is necessary because the NRC, in an equipment inspection, questioned the adequacy of the safety margins in the operating ranges of the Refueling Water Storage System, to prevent air entrainment in the piping if the water level in RWT tanks was reduced below the design minimums due to continuous pump suction. To comply with the NRC's recommendations, the RWT's instrumentation will be modified and additional vent lines will be added -- increasing the safety margins of the Refueling Water Storage System.	$ 161,434	$ 186,326	$ 347,760	4/30/2011
43.	090145	Building B - Classroom Addition	The purpose of this project is to construct a large classroom, capacity 65, to be used for Operator training. The site currently has several small classrooms near the simulators which are sufficient for most training required for new and requalifying operators. For those times, however, when the class size needs to be larger (i.e., interdisciplinary training, training for an entire shift), the site does not have sufficient space to accommodate the class. The Operations Department has expanded significantly recently to ensure it has the necessary operators to run the site as its aging work force begins retiring, increasing the demand for training and training rooms.	$ 274,529	$ 47,013	$ 321,542	1/21/2011

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
44.	100036	Fiber Optic & DS Line (Well for Firing Range)	The purpose of this project is to simultaneously rectify two current problems at PV: 1) the need for daily monitoring of the evaporation ponds, required by the Aquifer Protection Permit governing the ponds' operation, and 2) the need for potable water at the site firing range, which is next to the evaporation ponds. The scope of the project includes a 3.7 mile common trench that contains both a fiber optic line from the Water Reclamation control room in the Energy Information Center and a domestic service (DS) water line from U3. The fiber optic line terminates at the evaporation ponds and the DS water line terminates at the firing range. Because the fiber optic line permits remote monitoring of the evaporation ponds, daily trips to the ponds are eliminated, resulting in considerable man hour savings.	$ 316,570	$ 2,441	$ 319,011	1/19/2011
45.	090254	QA-1316-Fuel Bldg Normal Lighting Mod U3	The purpose of this project is replacement of the general area lighting in the fuel buildings in all 3 units to bring the illumination up to the level required by American National Standards Institute / Illuminating Engineering Society of North America standard RP-07-01. In several areas of these buildings, the illumination level is less than 25% of the minimum requirements, causing unsafe work conditions due to the poor visibility.	$ 58,468	$ 260,277	$ 318,745	10/28/2011
46.	090165	Chemistry Class Software Repl.	The purposes of this project are to: 1) develop a replacement for the Chemistry CLASS software application that captures and monitors the chemistry analyses and instrument calibrations at PV, and 2) integrate the new CLASS application's data sources with 2 other Chemistry applications -- LabMaster (used to monitor equipment) and Shift Logs (used to track technician workflow) -- that use the same data but require duplicate data entry at present. The replacement of CLASS is required because the programming language utilized for the application (Visual Basic 6) is no longer supported by the vendor (Microsoft), creating a security risk to the PV network that could be exploited because Microsoft will no longer provide software patches. A breach would allow an unauthorized user access to the site network. The second piece of the project -- combining disparate data entry for several Chemistry programs is justified economically as it will eliminate keying errors that cause data integrity issues.	$ 18,506	$ 294,423	$ 312,929	3/15/2012
47.	060069	UFM System Replacement, U3R15	Palo Verde currently uses Ultrasonic Flow Meters (UFM) and Venturi nozzles on the Feedwater system to determine Reactor Thermal Power. The UFM system in all three units have been experiencing an increasing rate of failures over the past few years, mainly caused by the electronics units. The purpose of the UFM upgrade is to remove the existing LEFM Model 8300 electronics unit (one electronic unit per PV unit) and replace it with 2 (one unit needed for each feedwater line) of the Model 2000FE electronic platforms.	$ 111,707	$ 195,201	$ 306,908	4/29/2012
48.	100122	Warehouse Admin Area Outside PA	The purpose of this project is to reconfigure the administrative area of the existing warehouse to support a more efficient workflow of Supply Chain functions. The admin area is currently out of compliance with National Electrical Code and National Fire Protection Association standards resulting in a habitability issue with the building. The reconfiguration of this area will bring it into compliance and provide for improved efficiency and workflow for the receipt and inspection of parts in the near term. For the long-term, this reconfigured area will be needed when areas of the Warehouse are used for shops and mock up areas as well as storage of large items and equipment.	$ 19,474	$ 266,293	$ 285,767	6/25/2011

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
49.	080052	Personnel Air Lock (PAL) Mod - Unit 3	This WA includes the design and replacement of all 4 Personal Air Lock (PAL) doors operating mechanisms in Unit 3. The PAL doors allow personnel to enter containment while still maintaining the integrity of the containment dome to control potential radioactive release.	$ 206,800	$ 68,976	$ 275,776	4/29/2012
50.	080075	LLRWSF Crane Control Replacement	The purpose of this project is to replace the remote controls for the low level radioactive waste storage facility crane which is used to handle low level radioactive waste materials. The current controls trip while the crane is under load which requires that the controls be reset. To date, this reset has allowed work to continue but there is concern that the controls will fail completely and result in a safety risk to the plant and personnel.	$ 132,653	$ 135,691	$ 268,344	9/15/2011
51.	110071	Equipment Reliability S/W - Phase 2	The purpose of this project is to implement four equipment reliability (ER) software modules, following on from Project # 090144: Equipment Reliability Integrated System, in which four ER software modules were also implemented. All eight of these modules in both projects are supplied by Insert Key Solutions (IKS), the leading vendor of ER software programs for the nuclear power generation industry. They provide a robust, integrated set of tools to manage the complex ER function. The IKS suite of modules are based on the INPO AP-913 document, "Equipment Reliability Process Description". The four modules in #110071 will replace two existing, in-house developed and supported applications / websites. Based on forecast efficiency gains in the equipment maintenance function, the project expects to produce considerable annual "soft-dollar" savings that give the project positive economic metrics.	$ 86,964	$ 176,810	$ 263,774	12/31/2011
52.	090088	Personnel Air Lock (PAL) Mod - Unit 1	This WA includes the design and replacement of all 4 Personal Air Lock (PAL) doors operating mechanisms in Unit 1. The PAL doors allow personnel to enter containment while still maintaining the integrity of the containment dome to control potential radioactive release.	$ -	$ 260,447	$ 260,447	11/5/2011
53.	090203	SC-942 Replacement pH/Conductivity Meters U1	The purpose of this replacement is to ensure reliable and accurate pH and conductivity analysis of the Secondary Chemistry (SC) system. All outdated and obsolete pH and conductivity analyzers and associated sensing units will be replaced with state of the art and cost saving multiple channel, multiple function instrumentation and sensors.	$ 76,731	$ 176,800	$ 253,531	12/15/2011
54.	080113	Control Room Entrance	The purpose of this project is to remodel the shift managers' offices as well as the corridor, airlock, calibration room, Shift Technical Advisor's office and kitchen in each unit. The area is degraded and lacks technology that will make the operators more efficient and ensure their safety.	$ 10,935	$ 241,521	$ 252,456	5/15/2012
55.	110022	Cathodic Protection 2011-Repl.	The scope of this project is to replace of anode beds to maintain cathodic protection of the underground piping and structures. The anode beds degrade over time as they perform their function and must be replaced periodically. The site has a Cathodic Protection program to ensure replacement of the beds so as to allow them to continue providing their protective function.	$ -	$ 252,365	$ 252,365	12/15/2011

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
56.	100221	Glass Top Simulators	The purpose of this project is to procure 11 virtual simulation control panels (common name - Glass Top Simulators) and to install them at strategic site locations to address problems with access to the two full-scope, plant-referenced simulators. Demands on the full-scope simulators are increasing due to: 1) larger classes for operator training, 2) additional training courses for Operations and Engineering (e.g., Just In Time Training), and 3) personnel requiring simulator access to model proposed plant modifications. The Glass Top Simulators will meet this demand for additional simulator time and reduce pressure on the full-scope simulators. An economic analysis of the "soft-dollar" benefits of the Glass Top Simulators indicated substantial positive returns on this investment by increasing the efficiency of the site's training classes and improving the process of designing complex plant modifications.	$ 155,079	$ 84,114	$ 239,193	2/10/2011
57.	110100	Condensate Polisher Rubber Relining - U2	The purpose of this project is the replacement of the worn out rubber relining of the polishers in the condensate system.	$ -	$ 224,601	$ 224,601	12/1/2011
58.	100002	WRF GF Filter Media - 2011 Scope	The purpose of this project is replacement of the filter media (composed of sand and coal) in the gravity filter system at the Water Reclamation Facility (WRF). The gravity filter system is an important step in the conversion of waste water influent to water sufficiently pure to use for cooling the nuclear units during production of power. Over time (about 12-15 years) the media becomes depleted and must be replaced.	$ -	$ 218,362	$ 218,362	12/1/2011
59.	100028	UFM System Replacement, U2R16	Palo Verde currently uses Ultrasonic Flow Meters (UFM) and Venturi nozzles on the Feedwater system to determine Reactor Thermal Power. The UFM system in all three units have been experiencing an increasing rate of failures over the past few years, mainly caused by the electronics units. The purpose of the UFM upgrade is to remove the existing LEFM Model 8300 electronics unit (one electronic unit per PV unit) and replace it with 2 (one unit needed for each feedwater line) of the Model 2000FE electronic platforms. platforms.	$ 85,786	$ 123,443	$ 209,229	4/30/2011
60.	090070	SWMS 2010 Project	The purpose of this WA is to upgrade the Site Work Management System (SWMS) software. The scope includes upgrades to the general user interface (improvements to 10 high-use forms & interface programming upgrades to improve functionality) and replacement of the systems interface between the PeopleSoft Human Resources system and SWMS to improve the timeliness and speed of data transfer between them. Benefits from the proposed upgrades include increased ease of use for all users across the site and reduced time to process incoming contractors. An economic analysis identified considerable "soft-dollar", personnel-related efficiencies from this project.	$ 103,475	$ 101,184	$ 204,659	6/28/2011
61.	110023	UFM System Replacement, U1R16	Palo Verde currently uses Ultrasonic Flow Meters (UFM) and Venturi nozzles on the Feedwater system to determine Reactor Thermal Power. The UFM system in all three units has been experiencing an increasing rate of failures over the past few years, mainly caused by the electronics units. The purpose of the UFM upgrade is to remove the existing LEFM Model 8300 electronics unit (one electronic unit per PV unit) and replace it with 2 (one unit needed for each feedwater line) of the Model 2000FE electronic platforms. platforms.	$ -	$ 199,920	$ 199,920	3/15/2012

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
62.	090063	Monitoring Wells (6)	The purpose of this project is to install six monitoring wells near the site's perimeter to enhance PV's capability for early detection of any contamination of ground water from inadvertent radiological releases. The project is required to comply with the 2007 initiative issued by the Nuclear Energy Institute (NEI), titled "Industry Ground Water Protection Initiative - Final Guidance Document", which was issued to respond to industry-wide concerns to increase protection of aquifers.	$ 110,587	$ 88,027	$ 198,614	5/31/2012
63.	100090	Dilute Caustic Tanks (2)	The purpose of this project is replacement of two dilute caustic tanks of 15,000 gallon capacity. Both the tanks and the associated concrete pads are showing signs of degradation and need to be replaced. Failure to replace these tanks and pads could ultimately result in a chemical spill, creating an environmental incident.	$ -	$ 182,653	$ 182,653	5/1/2012
64.	100113	WRF Chemical Production Bldg HVAC Ductwork	The purpose of this project is to purchase and install HVAC ductwork, duct heaters, controls, and roof exhaust fans in the chemical production building located at the Water Reclamation Facility, to replace degraded components. The chemical production building contains equipment for the production and storage of chemicals used at PVNGS. The HVAC system is designed to regulate temperature, maintain a slight positive air pressure in the building, and exhaust corrosive and hazardous gases. The HVAC system has suffered severe corrosion from high humidity and chemical vapors. Completion of this project will allow the building's HVAC system to meet the original design requirements.	$ 9,454	$ 173,095	$ 182,549	6/30/2011
65.	090130	RMS Server Replacement	The Radiation Monitoring System (RMS) is responsible for monitoring potential areas of radiological exposure and alerting plant personnel when there is an event which could impact plant personnel or public safety. The purpose of this project is to replace all of the existing hardware with new, supported Intel hardware and ensure that the latest version of Solaris will operate on it. A rule of thumb for electronic equipment reliable useful life, especially for equipment such as servers and hard drives is five years. This equipment has been working for 10 years.	$ 110,476	$ 63,071	$ 173,547	6/15/2011
66.	110048	WRF Cell Frame Replace 2011	The purpose of this project is to replace the sodium hypochlorite production skids used in the Water Reclamation Facility for biological control of water streams on the site. The site has two such skids, each of which is required to be rebuilt every three years due to degradation of the frame and cells from the chemicals used to produce sodium hypochlorite. This skid was last rebuilt in 2008.	$ -	$ 173,442	$ 173,442	12/31/2011
67.	110116	Roof Replacements - 2011 WRF	The purpose of this project is to replace or repair degraded roofs as identified in a site roof study. Roofs were evaluated and a timeline was established to replace or repair the most degraded roofs first. This plan is being executed over a number of years.	$ 65,003	$ 97,288	$ 162,291	10/28/2011

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
68.	110083	CW Tie In - Isolation Valve for Tower #1 - U2	The purpose of this project is to install an additional isolation valve in the circulating water tie-in system for Unit 2 - Cooling Tower #1. At the time of implementation of project ID #100111 for the circulating water (CW) tie-in work in U2R15, the valve assembly, piping, and vault were not installed on the 96" line to tower #1, due to outage time constraints. This project completes the work planned in project #100111, and brings the CW configuration of U2 into alignment with the other 2 units. Replacement of the existing isolation valve is required because when it is closed, the valve leaks at the rate of 200-300 gallons per minute, creating unsafe working conditions and presenting a risk of a leak to the aquifer during pumping operation to handle the water.	$ -	$ 161,370	$ 161,370	5/7/2011
69.	090253	QA-1316: Fuel Bldg Normal Lighting Mod U2	The purpose of this project is replacement of the general area lighting in the fuel buildings in all 3 units to bring the illumination up to the level required by American National Standards Institute / Illuminating Engineering Society of North America standard RP-07-01. In several areas of these buildings, the illumination level is less than 25% of the minimum requirements, causing unsafe work conditions due to the poor visibility.	$ -	$ 158,617	$ 158,617	3/2/2012
70.	110109	WRF Replacement FC Turn/Rake Drives - 2011	The purpose of this project is replacement of the turn drives and rake drives in the Water Reclamation Facility (WRF) clarifier filtering systems. These drives being replaced are original equipment and have reached the end of their useful lives. The drives are critical components in the clarifiers that remove solids from the influent that is purified and used in the cooling systems of the three units.	$ -	$ 155,973	$ 155,973	12/31/2011
71.	110027	FAC Mod, 2011	The purpose of this project is to replace carbon steel piping with stainless steel piping. All three PVNGS Units have experienced severe wall thinning in the carbon steel piping lines due to erosion / corrosion which could lead to piping system rupture. If the pipe ruptured, water flow necessary for plant operations would be interrupted.	$ -	$ 149,182	$ 149,182	11/11/2011
72.	100132	Site Schedule Adherence (On-Line KPI's)	The purpose of this project is to develop and implement a software program to collate and present key performance indicators (KPI's) for the on-line work management function. At present these metrics are obtained using an inefficient combination of: 1) Microsoft Access databases, 2) spreadsheets, and 3) manual numerical computations. This process produces conflicting results/ measurements. In addition, the current on-line work management performance monitoring system does not meet the needs of the station to align individual and work group performance to station goals. These deficiencies in current measurement keep the station from being aligned with industry best practice and do not support the station complying with pending revisions to INPO AP-928 "Work Management Process Description." This application will replace the disparate systems currently in use and remove the ambiguity of the current data by consistently obtaining the metric data from the source systems, which in turn will permit alignment to the station's Operational Focus indicators. An economic analysis of the "soft-dollar" efficiencies from this project indicates positive returns.	$ 10,735	$ 132,947	$ 143,682	12/15/2011

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
73.	110115	Roof Replacements - 2011 Unit 3	The purpose of this project is to replace or repair degraded roofs as identified in a site roof study. Roofs were evaluated and a timeline was established to replace or repair the most degraded roofs first. This plan is being executed over a number of years.	$ 38,369	$ 95,251	$ 133,620	11/28/2011
74.	110114	Roof Replacements - 2011 Unit 2	The purpose of this project is to replace or repair degraded roofs as identified in a site roof study. Roofs were evaluated and a timeline was established to replace or repair the most degraded roofs first. This plan is being executed over a number of years.	$ 62,143	$ 70,220	$ 132,363	8/26/2011
75.	110038	Roof Replacements - 2011 Unit 1	The purpose of this project is to replace or repair degraded roofs as identified in a site roof study. Roofs were evaluated and a timeline was established to replace or repair the most degraded roofs first. This plan is being executed over a number of years.	$ 63,222	$ 67,901	$ 131,123	6/25/2011
76.	100202	Cooling Tower NRQ Circuit Breakers-2012	The purpose of this project is to purchase and install new circuit breakers to replace the existing twenty one cooling tower fan breakers on the cooling towers. The breakers have been utilized in the cooling tower environment for over 20 years and need replacement/refurbishment to ensure safety and equipment reliability. The breaker is designed to isolate a fault and actuate a vibration switch to trip the breaker thereby removing the energy source for the cooling tower fans. Failure of these to operate as expected can cause significant physical damage to the cooling towers.	$ -	$ 122,229	$ 122,229	6/1/2012
77.	110099	Stairway in WRF Tunnels	The purpose of this project is to design, build and replace all three Spent Washwater Thickener tunnel stairways in the Water Reclamation Facility, bringing the stairways into OSHA compliance (OSHA Regulation 1910 Subpart D, Walking and Working Surfaces, Regulation 1926.1051, General Requirements, and Regulation 1926.1052). This scope addresses the findings of an inspection by WRF personnel and the PVNGS Safety Department that revealed stairways not in compliance with OSHA requirements. The design of the stairs will accommodate the riser requirement, allow required head clearance, provide a landing/entry way, and correct handrail deficiencies. The scope will also include demolition of the existing access systems and foundations, and relocation of electrical components.	$ 41,523	$ 77,576	$ 119,099	5/31/2011
78.	100083	CW Screen Gate Replacement-U3	The purpose of this project is to replace circulating water pump sliding screens with a set of two screens. The screens are designed to prevent debris from entering downstream components such as the condenser and causing tube leaks or negatively affecting condenser performance. Currently the system only has one screen which cannot easily be cleaned. The dual screen system will allow one screen to be lifted for cleaning while leaving the second in place.	$ -	$ 116,178	$ 116,178	8/31/2011
79.	120002	RCP Seals Replacement U3R16	The purpose of this project is the replacement of the reactor coolant pump seals during U3 outage, as part of the Long Range Plan (LRP) to maintain equipment reliability.	$ -	$ 114,636	$ 114,636	4/29/2012

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
80.	100234	CW Screen gate replacement-U1	The purpose of this project is to replace circulating water pump sliding screens with a set of two screens. The screens are designed to prevent debris from entering downstream components such as the condenser and causing tube leaks or negatively affecting condenser performance. Currently the system only has one screen which cannot easily be cleaned. The dual screen system will allow one screen to be lifted for cleaning while leaving the second in place.	$ -	$ 110,645	$ 110,645	8/31/2011
81.	100235	CW Screen Gate Replacement-U2	The purpose of this project is to replace circulating water pump sliding screens with a set of two screens. The screens are designed to prevent debris from entering downstream components such as the condenser and causing tube leaks or negatively affecting condenser performance. Currently the system only has one screen which cannot easily be cleaned. The dual screen system will allow one screen to be lifted for cleaning while leaving the second in place.	$ -	$ 110,338	$ 110,338	8/31/2011
82.	110091	ZT-1282 Turbine Building Roll-up Door	The purpose of this project is to install a new Roll-up door at the ground level on the north side of each turbine building to facilitate the movement of people and equipment into the building during outages and feed pump crane testing. This project will eliminate the need for the removal and replacement of the turbine building wall and the use of a temporary, less than optimally safe ramp for access.	$ -	$ 96,470	$ 96,470	4/30/2012
83.	100120	AO Briefing Room - Unit 3	The purpose of this project is to upgrade the Auxiliary Operator (AO) Briefing Rooms in Unit 3 by installing new technology to enable AOs to more efficiently perform their routine tasks and to allow a single briefing for operators in all three units at one time to enhance shift turnovers. The deficient layout was identified evaluated exercise and subsequent benchmarking at other sites. The project returned a positive net present value based on the efficiencies gained by the availability of improved technology.	$ -	$ 89,042	$ 89,042	5/15/2011
84.	090235	AO Briefing Rooms - Unit 1	The purpose of this project is to upgrade the Auxiliary Operator (AO) Briefing Rooms in Unit 1 by installing new technology to enable AOs to more efficiently perform their routine tasks and to allow a single briefing for operators in all three units at one time to enhance shift turnovers. The deficient layout was identified evaluated exercise and subsequent benchmarking at other sites. The project returned a positive net present value based on the efficiencies gained by the availability of improved technology.	$ -	$ 89,008	$ 89,008	4/15/2011
85.	100119	AO Briefing Rooms - Unit 2	The purpose of this project is to upgrade the Auxiliary Operator (AO) Briefing Rooms in Unit 2 by installing new technology to enable AOs to more efficiently perform their routine tasks and to allow a single briefing for operators in all three units at one time to enhance shift turnovers. The deficient layout was identified evaluated exercise and subsequent benchmarking at other sites. The project returned a positive net present value based on the efficiencies gained by the availability of improved technology.	$ 52,772	$ 35,666	$ 88,438	2/28/2011

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
86.	060068	Main Control Board for PVLAN, U3R15	The Main Control Board (MCB) Local Area Network project will install a secured fiber backbone in the control room boards and on the 120 foot of the control room that connects to the Palo Verde Local Area Network (PVLAN). Enough fiber will be installed throughout for future growth. Three switches and a media converter will also be installed. The fiber network is critical to upgrading the various communication systems to ensure reliability.	$ 56,212	$ 32,179	$ 88,391	4/29/2012
87.	110003	2011 RCP Seals Replacement U1R16	The purpose of this project is the replacement of the reactor coolant pump seals during U3 outage, as part of the Long Range Plan (LRP) to maintain equipment reliability.	$ -	$ 87,023	$ 87,023	11/5/2011
88.	090127	Potential Transformer Replacement - U1	The purpose of this project is to replace the 500 kV Potential Transformer. The 500 kV potential transformer (PT) is used to transform high output voltage to a reduced level that can be used for metering and protective relays. Each unit at Palo Verde Nuclear Generating Station (PVNGS) has three 500 kV PTs. The existing PT manufacturer will not refurbish the existing PT requiring the replacement.	$ -	$ 81,428	$ 81,428	11/3/2011
89.	090128	Potential Transformer Replacement - U2	The purpose of this project is to replace the 500 kV Potential Transformer. The 500 kV potential transformer (PT) is used to transform high output voltage to a reduced level that can be used for metering and protective relays. Each unit at Palo Verde Nuclear Generating Station (PVNGS) has three 500 kV PTs. The existing PT manufacturer will not refurbish the existing PT requiring the replacement.	$ -	$ 79,320	$ 79,320	4/30/2011
90.	110081	PRA Model Other External Events	The purpose of this WA is to develop and implement a Probabilistic Risk Assessment (PRA) - Other External Events (e.g. externally-caused flood, airplane crash). This project is required to comply with NRC Regulatory Guide 1.200 Rev. 2 (effective 4/1/10) to enable continued use of the PRA going for risk-informed regulatory applications. If this work is not performed, NRC approval of future Notices of Enforcement Discretion, Exigent Technical Specification changes, and numerous industry burden reduction initiatives that support shortened refueling outage durations would be in jeopardy due to the possibility that the NRC may not grant requests to extend intervals between equipment testing.	$ -	$ 73,659	$ 73,659	11/23/2011
91.	110087	Uninterruptible Power Supply - Simulator	The purpose of this project is to procure and install an uninterruptible power supply (UPS) to protect the site's simulators from power surges/outages. Building B, which houses the simulators, has had numerous power surges/outages in recent years. The simulators have many electronic components that are vulnerable to power surges, which will now be protected by the new UPS equipment.	$ -	$ 69,026	$ 69,026	4/20/2011
92.	100231	Chemistry Ion Chromatography (ICS)-U1	The scope of this project is to replace obsolete instruments used to control and minimize the concentrations of impurities in various secondary and primary plant systems. According to the vendor, the life expectancy of an Ion Chromatography System is about 7 to 10 years. PVNGS current instruments are over 15 years old and were declared obsolete by the vendor (Dionex Corporation).	$ 66,639	$ 1,542	$ 68,181	3/15/2011
93.	100075	Gamma Portal Monitors	The purpose of this project is to purchase replacement radiation monitors for obsolete units. The gamma portal monitors are used to scan personnel leaving the Radiological Controlled Area (RCA) to ensure that radiation levels are within acceptable ranges as established in nuclear industry standards.	$ 60,432	$ 2,330	$ 62,762	5/15/2011

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
94.	110086	Simulator: Develop DFWCS Emulation for PC's	The purpose of this project is to replace the plant's simulator emulation model, and install a PC based version, for the Digital Feed Water Control System (DFWCS). The current model is outdated and does not provide sufficient fidelity to the actual operation of the DFWCS. By improving the fidelity between the plant and simulators for the DFWCS, the incorporation of future planned modifications to this system will be facilitated.	$ -	$ 62,389	$ 62,389	12/31/2011
95.	090169	RP Tool Monitors	The purpose of this project is to purchase three SAM-12 monitors to replace the remaining obsolete Merlin Gerin tool monitor. The initial tool monitors were purchased approximately 14 years ago and the electronics (computer and high voltage modules) are obsolete. The new tool monitors are needed to continue required monitoring of articles from the RCA.	$ 57,084	$ 2,641	$ 59,725	6/15/2011
96.	100027	Main Control Board for PVLAN, U1	The Main Control Board (MCB) Local Area Network project will install a secured fiber backbone in the control room boards and on the 120 foot of the control room that connects to the Palo Verde Local Area Network (PVLAN). Enough fiber will be installed throughout for future growth. Three switches and a media converter will also be installed. The fiber network is critical to upgrading the various communication systems to ensure reliability.	$ 622	$ 57,861	$ 58,483	11/5/2011
97.	100230	Personnel Contamination Monitors-U3	The purpose of this project is to replace the Eberline PCM-2 contamination monitors at the RCA Egress in each Unit 3 with Canberra Argos-5AB contamination monitors to conform to industry practice of 30-35 nCi Co-60 or about 75-80 nCi of Cs-137, monitoring thresholds for personnel leaving the Radiological Controlled Area (RCA).	$ 53,918	$ 2,495	$ 56,413	6/15/2011
98.	100229	Personnel Contamination Monitors-U2	The purpose of this project is to replace the Eberline PCM-2 contamination monitors at the RCA Egress in each Unit 2 with Canberra Argos-5AB contamination monitors to conform to industry practice of 30-35 nCi Co-60 or about 75-80 nCi of Cs-137, monitoring thresholds for personnel leaving the Radiological Controlled Area (RCA).	$ 53,918	$ 2,495	$ 56,413	6/15/2011
99.	100228	Personnel Contamination Monitors-U1	The purpose of this project is to replace the Eberline PCM-2 contamination monitors at the RCA Egress in each Unit 1 with Canberra Argos-5AB contamination monitors to conform to industry practice of 30-35 nCi Co-60 or about 75-80 nCi of Cs-137, monitoring thresholds for personnel leaving the Radiological Controlled Area (RCA).	$ 53,918	$ 2,495	$ 56,413	6/15/2011
100.	100137	Personnel Contamination Monitors	The scope of this project is to purchase the Eberline PCM-2 contamination monitors at the Dry Active Waste Processing Storage facility will be replaced with Canberra Argos-5AB contamination monitors to conform to industry practice of 30-35 nCi Co-60 or about 75-80 nCi of Cs-137, monitoring thresholds for personnel leaving the Radiological Controlled Area (RCA).	$ 53,918	$ 2,495	$ 56,413	6/15/2011
101.	090138	Potential Transformer Replacement - Common	The purpose of this project is to replace the 500 kV Potential Transformer. The 500 kV potential transformer (PT) is used to transform high output voltage to a reduced level that can be used for metering and protective relays. Each unit at Palo Verde Nuclear Generating Station (PVNGS) has three 500 kV PTs. The existing PT manufacturer will not refurbish the existing PT requiring the replacement.	$ -	$ 54,197	$ 54,197	7/31/2011

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
102.	110040	Motor Replacements 2011 -U1	The purpose of this project is replacement of motors in Unit 1 >100 horsepower during fall refueling outage work. As part of the Long Range Plan these are being replaced systematically to preclude failure during operation.	$ -	$ 52,718	$ 52,718	12/15/2011
103.	070020	SI Check Valve Repl. 2011	The scope of this project is replacement of safety injection check valves in the refueling outages. As part of the preventive Maintenance Program these are being replaced systematically to preclude failure during operation.	$ -	$ 51,663	$ 51,663	5/6/2011
104.	110118	Pump Replacement 2011- U1	The purpose of this project is to replace thee pumps during the Unit 1 Fall Refueling Outage. As part of the Long Range Plan, these are being replaced systematically to preclude failure during operation.	$ -	$ 48,040	$ 48,040	12/1/2011
105.	100233	Chemistry Ion Chromatography (ICS)-U3	The scope of this project is to replace obsolete instruments used to control and minimize the concentrations of impurities in various secondary and primary plant systems. The life expectancy of an Ion Chromatography System is about 7 to 10 years. PVNGS current instruments are over 15 years old and were declared obsolete by the vendor (Dionex Corporation).	$ 44,426	$ 3,083	$ 47,509	9/15/2011
106.	100232	Chemistry Ion Chromatography (ICS)-U2	The scope of this project is to replace obsolete instruments used to control and minimize the concentrations of impurities in various secondary and primary plant systems. The life expectancy of an Ion Chromatography System is about 7 to 10 years. PVNGS current instruments are over 15 years old and were declared obsolete by the vendor (Dionex Corporation).	$ 44,426	$ 3,083	$ 47,509	9/15/2011
107.	020097	Rad Mon Sys Monitor Replacement U3	The purpose of this project is replacement of the monitors for the radiation monitoring system at unit 3, due to their age and poor condition. The Radiation Monitoring System (RMS) provides radiation level indication of radiological conditions throughout the plant to the operations staff. The microcomputers function independently to monitor radiation levels, initiate alarms, initiate trips and control sampling (process monitors).	$ 12,815	$ 33,940	$ 46,755	12/15/2011
108.	100155	Fire Alarm System - Service Building	The purpose of this project is to replace the Service Building Fire Alarm panel. This panel is obsolete and replacement parts cannot not be acquired. The PVNGS Fire Marshall has identified these panels as deficient and a safety hazard which will be eliminated with the completion of this project.	$ -	$ 46,275	$ 46,275	9/30/2011
109.	120018	FAC Mod, 2012	The purpose of this project is to replace carbon steel piping with stainless steel piping. All three PVNGS Units have experienced severe wall thinning in the carbon steel piping lines due to erosion / corrosion which could lead to piping system rupture. If the pipe ruptured, water flow necessary for plant operations would be interrupted.	$ -	$ 45,491	$ 45,491	4/29/2012
110.	110002	2011 RCP Seals Replacement U2R16	The purpose of this project is replacement of the reactor coolant pump seals during U2 outage, as part of the Long Range Plan (LRP). The scope of this project is to replace the reactor coolant pump seals after several operating cycles to preclude failure during operation.	$ -	$ 42,546	$ 42,546	5/7/2011
111.	100216	SOCA Video Intrusion Detection System	The purpose of this project is to install a video intrusion detection system to enhance site security. This system will address vulnerabilities identified in force-on-force drills and site security self assessments.	$ -	$ 39,166	$ 39,166	6/30/2012

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
112.	100219	DG Fire Rated Roll Up Door Repl - U3	The purpose of this project is to replace degraded and broken fire doors for the two diesel generators in Unit 3 to conform to fire safety regulations. The doors are original to the plant and have exceeded their expected useful life. The doors are held open to allow access to the diesel generators. In case of fire, a heat sensitive release allows the door to drop within a designated time period to ensure the diesels are protected from the fire.	$ 8,549	$ 29,375	$ 37,924	6/30/2011
113.	020096	Rad Mon Sys Monitor Replacement U2	The purpose of this project is replacement of the monitors for the radiation monitoring system at unit 2, due to their age and poor condition. The Radiation Monitoring System (RMS) provides radiation level indication of radiological conditions throughout the plant to the operations staff. The microcomputers function independently to monitor radiation levels, initiate alarms, initiate trips and control sampling (process monitors).	$ 2,375	$ 32,974	$ 35,349	12/15/2011
114.	100078	Pump Replacements 2011-U2	The purpose of this project is to replace four pumps during the Spring Unit 2 Refueling Outage. As part of the Long Range Plan, these are being replaced systematically to preclude failure during operation.	$ -	$ 34,341	$ 34,341	5/6/2011
115.	100157	Fire Alarm System - D Building	The purpose of this project is to replace the Building D Fire Alarm panel. This panel is obsolete and replacement parts cannot not be acquired. The PVNGS Fire Marshall has identified these panels as deficient and a safety hazard which will be eliminated with the completion of this project.	$ -	$ 30,850	$ 30,850	9/30/2011
116.	110034	WRF Tolleson Flow Meter Replacement	The purpose of this project is to replace the flow-meter at the Tolleson Water Treatment plant. It is used for billing purposes to determine the water sent to the plant. The current flow-meter is obsolete and not working consistently, and repair is more expensive than replacement.	$ -	$ 30,505	$ 30,505	6/30/2011
117.	100168	Pump Replacements 2012	The purpose of this project is to replace pumps during the Spring Refueling Outage. As part of the Long Range Plan, these are being replaced systematically to preclude failure during operation.	$ -	$ 30,442	$ 30,442	5/1/2012
118.	100237	Motor Replacements 2011 -U2	The scope of this WA is replacement of motors in Unit 2 >100 horsepower during spring refueling outage work. As part of the Long Range Plan, these are being replaced systematically to preclude failure during operation.	$ -	$ 29,782	$ 29,782	5/6/2011
119.	110001	Main Cond Expansion Joint U1R16	The scope of this project is to replace main condenser expansion joints in regular 10 year intervals, as part of the Long Range Plan (LRP). It has been determined that the life expectancy of the expansion joints is approximately 10 years after which the seals become subject to failure. Failure of the seals allows air to enter the condenser and cause a turbine trip.	$ -	$ 26,107	$ 26,107	11/11/2011
120.	100062	Chemistry Ion Chromatography Systems (ICS)	The scope of this project is to replace obsolete instruments used to control and minimize the concentrations of impurities in various secondary and primary plant systems. The life expectancy of an Ion Chromatography System is about 7 to 10 years. PVNGS current instruments are over 15 years old and were declared obsolete by the vendor (Dionex Corporation).	$ 22,213	$ 3,084	$ 25,297	9/15/2011
121.	100258	Hoisting Equipment -JIB Crane	The purpose of this project is to purchase and install two new 5 ton capacity JIB cranes that would mount to the top of the main generator hydrogen domes. The cranes would allow the site to work on both ends of the generator at one time and free up the existing crane to support turbine work.	$ -	$ 24,956	$ 24,956	12/1/2011

Nuclear Generation Post-Test Year Plant Additions

Line No.	WA #	Project Description	Purpose	Project Cost to Date 12/31/2010	Cost to Complete	Projected Closed Cost	Estimated In-Service Date
122.	100238	Motor Replacement 2011 -U3	The purpose of this project is to replace motors in U3 as part of the online schedule work. As part of the Long Range Plan, these are being replaced systematically to preclude failure during operation.	$ -	$ 20,277	$ 20,277	12/1/2011
123.	110026	Super Mic/Dimensional Calibration	The scope of this project is to replace the dimensional calibration tool used in the testing and calibration of plant equipment.	$ -	$ 17,094	$ 17,094	11/20/2011
124.	100218	DG Fire Rated Roll Up Door Repl - U2	The purpose of this project is to replace degraded and broken fire doors for the two diesel generators in Unit 2 to conform to fire safety regulations. The doors are original to the plant and have exceeded their expected useful life. The doors are held open to allow access to the diesel generators. In case of fire, a heat sensitive release allows the door to drop within a designated time period to ensure the diesels are protected from the fire.	$ -	$ 7,741	$ 7,741	10/31/2011
125.	100217	DG Fire Rated Roll Up Door Repl - U1	The purpose of this project is to replace degraded and broken fire doors for the two diesel generators in Unit 1 to conform to fire safety regulations. The doors are original to the plant and have exceeded their expected useful life. The doors are held open to allow access to the diesel generators. In case of fire, a heat sensitive release allows the door to drop within a designated time period to ensure the diesels are protected from the fire.	$ 45	$ 7,687	$ 7,732	8/31/2011
126.	**Total Nuclear Generation Post-Test Year Plant Additions**			**$ 65,348,526**	**$ 54,754,862**	**$ 120,103,388**	