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# OPEN MEETING

**MEMORANDUM**

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AZ CORP COMMISSION
DOCKET CONTROL

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Arizona Corporation Commission
DOCKETED

MAY 12 2009

DOCKETED BY

TO: THE COMMISSION

FROM: Utilities Division

DATE: May 12, 2009

RE: ARIZONA PUBLIC SERVICE COMPANY - APPLICATION FOR APPROVAL OF A DEMAND RESPONSE PROGRAM (DOCKET NO. E-01345A-08-0569)

## I. Background

On November 6, 2008, Arizona Public Service Company ("APS" or "Company") filed an application for approval of a demand response ("DR") program for commercial and industrial customers ("C&I Load Management Program"). Commission Decision No. 69663 (June 28, 2007) ordered APS to file a cost-effective DR program that the Company believes would be most beneficial to its system and its customers. As the Commission noted in its Decision, an effective DR program can reduce variable power supply costs during peak load periods, and defer the need for additional capacity.

On April 28, 2009, APS filed a supplement to its request expanding eligibility for the DR program to include commercial and industrial customers who receive electric service under an APS partial requirements rate schedule.

On June 30, 2008, APS filed a study identifying Demand Response programs that may be feasible for APS and its customers. APS considered 13 demand reduction techniques, as summarized below. The proposed C&I Load Management Program is a load control type of program. Programs other than a C&I load control program were in general not suitable because:

a) customer participation would be low,

b) the technology was not mature,

c) similar results could be accomplished through rate design or existing programs such as the Renewable Energy Standard and Tariff ("REST"), or

d) the program was not suitable to APS' system operational characteristics.

## II. Demand Response Measures Considered

**Residential Air Conditioning ("A/C") Cycling** A/C cycling allows the utility to remotely control demand during peak periods by cycling A/C units on and off for a portion of an hour. Although air conditioning is a primary component of summer peak, surveys conducted for APS indicated a low percentage of customers showing interest.

**Residential Misc. Load Cycling** This is similar to A/C cycling, but controlling other loads such as water heaters or pool pumps. APS points out that water heater loads are not a significant contribution to summer peaks, and that most APS customers with pools have the pumps on timers and are off-peak with time-of-use ("TOU") rates.

**Commercial & Industrial Load Control** This is potentially economical and attractive to customers. There are multiple end-use applications at commercial and industrial sites that would be available for load reductions. APS has chosen this option for its proposed demand response program as discussed below.

**Thermal Energy Storage** Thermal Energy Storage ("TES") programs typically assist customers in acquiring and installing ice or chilled water storage systems that are then used to shift A/C load to off-peak hours. This is accomplished by using the existing chiller equipment to make either ice or cold water during off-peak hours, and then using this source to cool the customer's site during the on-peak hours. This effectively shifts the cooling load for a building to the nighttime hours when it is less expensive for the utility to generate electricity. TES technology has potential, and requires additional research and assessment. Smaller systems applicable to residential and small commercial customers are becoming increasingly available, but siting of storage equipment is often a barrier to installation.

**Scheduled Water Pumping** APS has Commission-approved time-of-use rate options for water pumping, but with very low participation. Scheduled Water Pumping was not considered for a demand response program since there are opportunities to increase customer participation in time-of-use water pumping rates.

**Battery Storage** APS is not pursuing a Battery Storage program at this time. The Company would continue to test the technology and monitor advancements, and would reconsider it in the future.

**Curtailable/Interruptible Rates** APS has had previous experience with interruptible rate contracts. Customers who would choose interruptible rates would likely be the same customers who would choose the proposed C&I Load Control program.

**Demand Bidding and Buyback ("DBB")** With this option, customers propose load reductions at an agreed-to price. These programs work best for large customers and with utilities that have more volatile day-ahead or hourly market pricing and that are part of an Independent System Operator or Regional Transmission Operator. Therefore, APS is not pursuing DBB at this time as it is less optimal than other Commercial and Industrial programs.

**Standby Generation** For purposes of the DR Study, Standby Generation may be considered as a component of Distributed Generation ("DG"), which could be broken into two categories: Renewable DG and Standby. Renewable DG is well-supported by the REST, and involves providing customers incentive payments to encourage the development of renewable DG resources.

Standby Generation programs would use customer-owned standby generation, typically fueled by oil or natural gas, and which is dispatched by the utility when needed to meet demand. The utility would call upon the customer to begin production from the customer's standby DG unit, thus having the same effect as reducing that customer's load. Standby Generation, specifically when located within a load pocket, provides the added benefit of increasing the electrical system's reliability by reducing the stress on grid components, supporting local voltage levels, and increasing the diversity of power supply.

APS believes Standby Generation (other than REST DG) may have potential, but requires further study of its costs, operational considerations, and air pollution issues.

**Vehicle-to-Grid** This technology takes advantage of plug-in electric vehicles, using the vehicle's battery as a resource at peak periods. A two-way power flow is established, charging when able and feeding power back to shave utility peak loads. APS is not pursuing it at this time due to the infancy of the technology and a scarcity of plug-in vehicles. APS would monitor the technology and reconsider it in the future.

**Residential Super Peak** APS has filed for approval of a TOU rate including a "super peak" in the recent general rate case filing.[1] A "super peak" rate is a unique time-of-use pricing plan that prices energy use at the highest peak load times even higher than the normal on-peak price.

**Critical Peak Pricing** Critical Peak Pricing ("CPP") sets a very high energy rate during certain critical hours. It is different from a super peak rate in that Customers on the program would be notified a day in advance of a critical period, and thus given the opportunity to reduce load during that period and avoid the higher charges. APS has filed for approval of a Critical Peak Pricing tariff pilot program in the on-going general rate case.

**Real-Time Pricing** Real-Time Pricing ("RTP") programs utilize prices that fluctuate hourly with the commodity market for power. Utilities tend to post these prices on a day-ahead basis, and they are applied to a customer's usage. RTP appears to be less beneficial to APS customers than the two other Time-Differentiated Rate programs previously discussed (Super Peak and Critical Peak Pricing). APS will, however, continue to monitor industry experience in this area. RTP tends to be more expensive to implement and is better targeted to C&I customers who can manage their usage to reduce the risks of hourly fluctuations in prices. Based on research performed prior to the rate case filing, RTP is generally less effective in reducing peak load than either TOU or CPP.

APS is not pursuing real-time pricing at this time. The Company believes it is better suited for utilities with more highly liquid and transparent hourly market prices.

## III. Overview of Proposed C&I Program

In October of 2007, APS issued a targeted Request for Proposals ("RFP") to eleven experienced companies who could provide a demand response program for APS. APS has contracted with Alternative Energy Resources, Inc. ("AER"), a unit of Comverge, Inc. Comverge

[1] Docket No. E-01345A-08-0172

has operational load management and DR service contracts totaling 500 MW of capacity with utility clients including ISO New England, Public Service Company of New Mexico, Nevada Power, Rocky Mountain Power, San Diego Gas & Electric, and Pacific Gas & Electric. Contracts were originated under the Comverge name, and transferred to AER upon its formation in 2007.

Staff has contacted these utilities and their regulatory bodies and found that both regulators and utilities are satisfied with AER's performance.

RFP respondents' proposals to APS, other than AER, when geared to APS' needs, were not cost beneficial. The bidders' proposals showed benefit/cost ratios less than one and had restrictions such as limits on callable events (i.e., interruptible hours).

APS has chosen a C&I load control type of program for its proposed demand response program, and would use a third party "aggregator" business model for the program. APS does not currently have the systems, resources, or experience necessary to directly manage such a DR program.

APS indicates that the use of AER offers definite benefits including:

a) specific knowledge, resources, and systems that APS currently lacks,

b) assumption of all risks associated with customer performance, and

c) guaranteed load reductions when required, with payment only for verified reductions, and penalties for nonperformance.

When the program is fully operational, AER would provide APS with up to 100 megawatts ("MW') of load reduction capability during the summer months in APS' Phoenix and Yuma service areas. The DR program would ramp-up over a three-year period, beginning with 30 MW in June 2010 and increasing to 100 MW by 2012. The program would provide firm load reduction capability, similar in availability and run time to a combustion turbine. The 15-year contract requires AER to provide verified, measurable load reductions, which allows APS to view this resource as firm capacity for system reliability purposes. Although some proposals were for shorter contract length, costs were much higher as the shorter contract term required bidders to recover their initial investment over a shorter time period. APS believes that the contract negotiated with AER is in the best interests of both the Company and its customers.

The proposed DR program would offer eligible commercial and industrial customers financial incentives to reduce electricity usage during summer system peak periods. This system peak reduction would be accomplished through a combination of direct load control and manual load reductions at the customer's site.

APS anticipates that approximately 10,000 customers may ultimately participate in this program. The DR program would be in effect during the peak demand months of June through September beginning in 2010; the DR resource would be available during the peak hours of 12 noon until 8:00 p.m. during those months. As a participant, a customer would agree to reduce energy usage upon receiving notice from AER. Incentive payments to customers would be managed by AER and would vary based on the agreed-upon participation levels of each customer. Customers who did not reduce load as directed by AER would be removed from the program.

Because the DR program is a new offering to APS' customers, an extensive customer education and outreach program would be necessary to make certain that a sufficient number of customers participate and provide the expected load reduction benefits. Additionally, implementation of the program would involve interfaces with APS' information technology, account management, metering, and grid operations so the Company estimates it would take approximately one year to incorporate this new resource into the system. For that reason, APS is requesting that the Commission approve the DR Program by May 29, 2009 to ensure that the program is operational for the 2010 summer.

## IV. Benefit / Cost Analysis

As described above in Section II, APS investigated several possible demand response programs. Of those that had potential, the proposed C&I DR program demonstrates the highest benefit to cost ratio using the Societal Cost Test.

The Commission's 1991 Resource Planning Decision established the Societal Cost Test as the methodology to be used for determining the cost-effectiveness of a program such as this. Under the Societal Test; in order to be cost-effective; the ratio of benefits to costs, that is, the net present value of benefits divided by the net present value of costs, must be greater than one. This is the Benefit/Cost ("B/C") ratio. The incremental benefits to society of a program must exceed the incremental cost of having the program in place on a present value basis. Societal costs for a program include the cost of implementing the program, excluding any rebates. The societal benefits of the program include deferred or avoided generation capacity and energy costs and reduced water consumption and emissions.

APS' analysis indicates a B/C ratio of 2.26. Staff disagrees with APS' proposed handling of the incentive payments in APS' benefit/cost analysis. AER would pay incentives to customers under the contract. Correcting the calculation of benefit to cost for the inclusion of these payments, Staff's analysis gives a B/C ratio of 1.36.

Neither Staff's nor APS' economic analyses included quantification of the benefits of reduced emissions and water use that are anticipated; inclusion would increase the net present value and the B/C ratio.

Table 1 below shows that APS' annual [redacted]

Table 1 also illustrates that regardless of the assumed operational characteristics, the DR program is cost effective with B/C ratios ranging from 1.32 to 1.40.

Pricing to APS is shown in Table 2. APS has indicated that the program would have availability and run time similar to a combustion turbine peaker ("CT"). To achieve an annual cost (i.e., revenue requirement) [redacted]

**TABLE 1**
**APS Demand Response Program**
**Minimum/Maximum Exposure[1]**

| | [redacted] | [redacted] | [redacted] |
|---|---|---|---|
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | [redacted] | [redacted] | [redacted] |

[redacted]

[redacted]

[redacted]

[redacted]

**TABLE 2**
**APS Demand Response Program**
**Pricing**

| |
|---|
| [redacted] |
| [redacted] |
| [redacted] |
| [redacted] |
| [redacted] |
| [redacted] |
| |
| [redacted] |
| [redacted] |
| [redacted] |

## V. Cost Recovery

APS believes that the Demand Side Management Adjustor Clause ("DSMAC") is the appropriate cost-recovery mechanism for this program. APS stated in its application:

> Pursuant to Decision No. 67744 the DSMAC is the appropriate mechanism to recover program costs for the C&I Load Management program, including contract costs and program implementation, operational and management costs, and performance incentives. If the program is approved, APS also requests that the Commission acknowledge that the Company should treat these program costs in the same manner as all other energy efficiency programs, which are flowed through the DSMAC.

Staff agrees with this proposal to some extent. As the Company has stated, it wishes to have the Commission "treat these program costs in the same manner as all other energy efficiency programs." However, the C&I DR Program, although a type of demand-side management, is not an energy efficiency program which, according to Decision No. 67744, may be eligible for a performance incentive based on a share of the net economic benefits. As APS stated in its RFP dated October 25, 2007, "APS is not seeking conservation programs of any type or…energy efficiency …"

Staff recommends that C&I Load Management Program costs be recovered by APS through the DSM adjustment mechanism but without any performance incentive.

## VI. Eligibility

APS' contract with AER would allow participation by all C&I customers. [redacted]

## VII. Staff Recommendations

Staff recommends that APS' C&I Load Management Program be approved as discussed herein. No explicit approval of the APS/AER contract is recommended.

Staff recommends that program costs of the C&I Load Management Program be recovered by APS through the DSM adjustment mechanism, without any performance incentive.

Ernest G. Johnson
Director
Utilities Division

EGJ:JJP:lhm\CH

ORIGINATOR: Jeffrey Pasquinelli

**BEFORE THE ARIZONA CORPORATION COMMISSION**

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BOB STUMP
Commissioner

| | |
|---|---|
| IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S APPLICATION FOR APPROVAL OF A DEMAND RESPONSE PROGRAM | DOCKET NO. E-01345A-08-0569<br>DECISION NO. __________<br>ORDER |

Open Meeting
May 27 and 28, 2009
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

1. Arizona Public Service Company ("APS" or "Company") is certificated to provide electric service as a public service corporation in the State of Arizona.

2. On November 6, 2008, APS filed an application for approval of a demand response ("DR") program for commercial and industrial customers ("C&I Load Management Program").

3. Arizona Corporation Commission ("Commission") Decision No. 69663 (June 28, 2007) ordered APS to file a cost-effective DR program that the Company believes would be most beneficial to its system and its customers. As the Commission noted in its Decision, an effective DR program can reduce variable power supply costs during peak load periods, and defer the need for additional capacity.

4. On April 28, 2009, APS filed a supplement to its request expanding eligibility for the DR program to include commercial and industrial customers who receive electric service under an APS partial requirements rate schedule.

## I. Background

5. On June 30, 2008, APS filed a study identifying demand response programs that may be feasible for APS and its customers. APS considered 13 demand reduction techniques, as summarized below. The proposed C&I Load Management Program is a load control type of program. Programs other than a C&I load control program were in general not suitable because:

a) customer participation would be low,

b) the technology was not mature,

c) similar results could be accomplished through rate design or existing programs such as the Renewable Energy Standard and Tariff ("REST"), or

d) the program was not suitable to APS' system operational characteristics.

## II. Demand Response Measures Considered

6. **Residential Air Conditioning ("A/C") Cycling** A/C cycling allows the utility to remotely control demand during peak periods by cycling A/C units on and off for a portion of an hour. Although air conditioning is a primary component of summer peak, surveys conducted for APS indicated a low percentage of customers showing interest.

7. **Residential Misc. Load Cycling** This is similar to A/C cycling, but controlling other loads such as water heaters or pool pumps. APS points out that water heater loads are not a significant contribution to summer peaks, and that most APS customers with pools have the pumps on timers and are off-peak with time-of-use ("TOU") rates.

8. **Commercial & Industrial Load Control** This is potentially economical and attractive to customers. There are multiple end-use applications at commercial and industrial sites that would be available for load reductions. APS has chosen this option for its proposed demand response program as discussed below.

9. **Thermal Energy Storage** Thermal Energy Storage ("TES") programs typically assist customers in acquiring and installing ice or chilled water storage systems that are then used to shift A/C load to off-peak hours. This is accomplished by using the existing chiller equipment to make either ice or cold water during off-peak hours, and then using this source to cool the

customer's site during the on-peak hours. This effectively shifts the cooling load for a building to the nighttime hours when it is less expensive for the utility to generate electricity. TES technology has potential, and requires additional research and assessment. Smaller systems applicable to residential and small commercial customers are becoming increasingly available, but siting of storage equipment is often a barrier to installation.

10. **Scheduled Water Pumping** APS has Commission-approved time-of-use rate options for water pumping, but with very low participation. Scheduled Water Pumping was not considered for a demand response program since there are opportunities to increase customer participation in time-of-use water pumping rates.

11. **Battery Storage** APS is not pursuing a Battery Storage program at this time. The Company would continue to test the technology and monitor advancements, and would reconsider it in the future.

12. **Curtailable/Interruptible Rates** APS has had previous experience with interruptible rate contracts. Customers who would choose interruptible rates would likely be the same customers who would choose the proposed C&I Load Control program.

13. **Demand Bidding and Buyback ("DBB")** With this option, customers propose load reductions at an agreed-to price. These programs work best for large customers and with utilities that have more volatile day-ahead or hourly market pricing and that are part of an Independent System Operator or Regional Transmission Operator. Therefore, APS is not pursuing DBB at this time, as it is less optimal than other Commercial and Industrial programs.

14. **Standby Generation** For purposes of the DR Study, Standby Generation may be considered as a component of Distributed Generation ("DG"), which could be broken into two categories: Renewable DG and Standby. Renewable DG is well-supported by the REST, and involves providing customers incentive payments to encourage the development of renewable DG resources.

15. Standby Generation programs would use customer-owned standby generation, typically fueled by oil or natural gas, and which is dispatched by the utility when needed to meet demand. The utility would call upon the customer to begin production from the customer's

standby DG unit, thus having the same effect as reducing that customer's load. Standby Generation, specifically when located within a load pocket, provides the added benefit of increasing the electrical system's reliability by reducing the stress on grid components, supporting local voltage levels, and increasing the diversity of power supply.

16. APS believes Standby Generation (other than REST DG) may have potential, but requires further study of its costs, operational considerations, and air pollution issues.

17. **Vehicle-to-Grid** This technology takes advantage of plug-in electric vehicles, using the vehicle's battery as a resource at peak periods. A two-way power flow is established, charging when able and feeding power back to shave utility peak loads. APS is not pursuing it at this time due to the infancy of the technology and a scarcity of plug-in vehicles. APS would monitor the technology and reconsider it in the future.

18. **Residential Super Peak** APS has filed for approval of a TOU rate including a "super peak" in the recent general rate case filing.[1] A "super peak" rate is a unique time-of-use pricing plan that prices energy use at the highest peak load times even higher than the normal on-peak price.

19. **Critical Peak Pricing** Critical Peak Pricing ("CPP") sets a very high energy rate during certain critical hours. It is different from a super peak rate in that Customers on the program would be notified a day in advance of a critical period, and thus given the opportunity to reduce load during that period and avoid the higher charges. APS has filed for approval of a Critical Peak Pricing tariff pilot program in the on-going general rate case.

20. **Real-Time Pricing** Real-Time Pricing ("RTP") programs utilize prices that fluctuate hourly with the commodity market for power. Utilities tend to post these prices on a day-ahead basis, and they are applied to a customer's usage. RTP appears to be less beneficial to APS customers than the two other Time-Differentiated Rate programs previously discussed (Super Peak and Critical Peak Pricing). APS will, however, continue to monitor industry experience in this area. RTP tends to be more expensive to implement and is better targeted to C&I customers who

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[1] Docket No. E-01345A-08-0172

can manage their usage to reduce the risks of hourly fluctuations in prices. Based on research performed prior to the rate case filing, RTP is generally less effective in reducing peak load than either TOU or CPP.

21. APS is not pursuing real-time pricing at this time. The Company believes it is better suited for utilities with more highly liquid and transparent hourly market prices.

## III. Overview of Proposed C&I Program

22. In October of 2007, APS issued a targeted Request for Proposals ("RFP") to eleven experienced companies who could provide a demand response program for APS. APS has contracted with Alternative Energy Resources, Inc. ("AER"), a unit of Comverge, Inc. Comverge has operational load management and DR service contracts totaling 500 MW of capacity with utility clients including ISO New England, Public Service Company of New Mexico, Nevada Power, Rocky Mountain Power, San Diego Gas & Electric, and Pacific Gas & Electric. Contracts were originated under the Comverge name, and transferred to AER upon its formation in 2007.

23. Staff has contacted these utilities and their regulatory bodies and found that both regulators and utilities are satisfied with AER's performance.

24. RFP respondents' proposals to APS, other than AER, when geared to APS needs, were not cost beneficial. The bidders' proposals showed benefit/cost ratios less than one and had restrictions such as limits on callable events (i.e., interruptible hours).

25. APS has chosen a C&I load control type of program for its proposed demand response program, and would use a third party "aggregator" business model for the program. APS does not currently have the systems, resources, or experience necessary to directly manage such a DR program.

26. APS indicates that the use of AER offers definite benefits including:

a) specific knowledge, resources, and systems that APS currently lacks,

b) assumption of all risks associated with customer performance, and

c) guaranteed load reductions when required, with payment only for verified reductions, and penalties for nonperformance.

. . .

27. When the program is fully operational, AER would provide APS with up to 100 megawatts ("MW") of load reduction capability during the summer months in APS' Phoenix and Yuma service areas. The DR program would ramp up over a three-year period, beginning with 30 MW in June 2010 and increasing to 100 MW by 2012. The program would provide firm load reduction capability, similar in availability and run time to a combustion turbine. The 15-year contract requires AER to provide verified, measurable load reductions, which allows APS to view this resource as firm capacity for system reliability purposes. Although some proposals were for shorter contract length, costs were much higher as the shorter contract term required bidders to recover their initial investment over a shorter time period. APS believes that the contract negotiated with AER is in the best interests of both the Company and its customers.

28. The proposed DR program would offer eligible commercial and industrial customers financial incentives to reduce electricity usage during summer system peak periods. This system peak reduction would be accomplished through a combination of direct load control and manual load reductions at the customer's site.

29. APS anticipates that approximately 10,000 customers may ultimately participate in this program. The DR program would be in effect during the peak demand months of June through September beginning in 2010; the DR resource would be available during the peak hours of 12 noon until 8:00 p.m. during those months. As a participant, a customer would agree to reduce energy usage upon receiving notice from AER. Incentive payments to customers would be managed by AER and would vary based on the agreed-upon participation levels of each customer. Customers who did not reduce load as directed by AER would be removed from the program.

30. Because the DR program is a new offering to APS' customers, an extensive customer education and outreach program would be necessary to make certain that a sufficient number of customers participate and provide the expected load reduction benefits. Additionally, implementation of the program would involve interfaces with APS' information technology, account management, metering, and grid operations so the Company estimates it would take

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approximately one year to incorporate this new resource into the system. For that reason, APS is requesting that the Commission approve the DR Program by May 29, 2009, to ensure that the program is operational for the 2010 summer.

## IV. Benefit / Cost Analysis

31. As described above in Section II, APS investigated several possible demand response programs. Of those that had potential, the proposed C&I DR program demonstrates the highest benefit to cost ratio using the Societal Cost Test.

32. The Commission's 1991 Resource Planning Decision established the Societal Cost Test as the methodology to be used for determining the cost-effectiveness of a program such as this. Under the Societal Test; in order to be cost-effective; the ratio of benefits to costs, that is, the net present value of benefits divided by the net present value of costs, must be greater than one. This is the Benefit/Cost ("B/C") ratio. The incremental benefits to society of a program must exceed the incremental cost of having the program in place on a present value basis. Societal costs for a program include the cost of implementing the program, excluding any rebates. The societal benefits of the program include deferred or avoided generation capacity and energy costs and reduced water consumption and emissions.

33. APS' analysis indicates a B/C ratio of 2.26. Staff disagrees with APS' proposed handling of the incentive payments in APS' benefit/cost analysis. AER would pay incentives to customers under the contract. Staff corrected the calculation of benefits to costs for the inclusion of these payments. Consequently, Staff's analysis gives a B/C ratio of 1.36.

34. Neither Staff's nor APS' economic analyses included quantification of the benefits of reduced emissions and water use that are anticipated; inclusion would increase the net present value and the B/C ratio.

35. Staff has demonstrated that the minimum and maximum costs APS would be exposed to are within reason, and that regardless of the assumed operational characteristics, the DR program is cost effective with B/C ratios ranging from 1.32 to 1.40.

36. APS has indicated that the program would have availability and run time similar to a combustion turbine peaker ("CT"). Staff has shown that the program costs would be

substantially less than the installed cost of a new unit.

## V. Cost Recovery

37. APS believes that the Demand Side Management Adjustor Clause ("DSMAC") is the appropriate cost-recovery mechanism for this program. APS stated in its application:

> Pursuant to Decision No. 67744 the DSMAC is the appropriate mechanism to recover program costs for the C&I Load Management program, including contract costs and program implementation, operational and management costs, and performance incentives. If the program is approved, APS also requests that the Commission acknowledge that the Company should treat these program costs in the same manner as all other energy efficiency programs, which are flowed through the DSMAC.

38. Staff agrees with this proposal to some extent. As the Company has stated, it wishes to have the Commission "treat these program costs in the same manner as all other energy efficiency programs." However, the C&I DR Program, although a type of demand-side management, is not an energy efficiency program, which, according to Decision No. 67744, may be eligible for a performance incentive based on a share of the net economic benefits. As APS stated in its RFP dated October 25, 2007, "APS is not seeking conservation programs of any type or…energy efficiency …"

39. Staff has recommended that C&I Load Management Program costs be recovered by APS through the DSM adjustment mechanism but without any performance incentive.

## VI. Eligibility

40. APS' contract with AER would allow participation by all C&I customers.

## VII. Staff Recommendations

41. Staff has recommended that APS' C&I Load Management Program be approved as discussed herein. No explicit approval of the APS/AER contract is recommended.

42. Staff has recommended that program costs of the C&I Load Management Program be recovered by APS through the DSM adjustment mechanism, without any performance incentive.

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## CONCLUSIONS OF LAW

1. Arizona Public Service Company is a public service corporation within the meaning of Article XV of the Arizona Constitution.

2. The Commission has jurisdiction over Arizona Public Service Company and the subject matter of the application.

3. The Commission, having reviewed the application and Staff's Memorandum dated May 12, 2009, concludes that it is in the public interest to approve the proposed Demand Response Program.

## ORDER

IT IS THEREFORE ORDERED that the Arizona Public Service Company C&I Load Management Program be and hereby is approved as discussed herein.

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IT IS FURTHER ORDERED that program costs of the C&I Load Management Program be recovered by Arizona Public Service Company through the DSM adjustment mechanism, without any performance incentive.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

**BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION**

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, MICHAEL P. KEARNS, Interim Executive Director of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this _______day of ___________________ , 2009.

_______________________________
MICHAEL P. KEARNS
INTERIM EXECUTIVE DIRECTOR

DISSENT: ____________________________

DISSENT: ____________________________

EGJ:JJP:lhm\CH

SERVICE LIST FOR ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0569

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Arizona Public Service Company
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Mail Station 8695
Phoenix, Arizona 85072-3999

Mr. C. Webb Crockett
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Arizonans for Electric Choice and Competition
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Phoenix, Arizona 85012-2913

Mr. Ernest G. Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Ms. Janice M. Alward
Chief Counsel, Legal Division
Arizona Corporation Commission
1200 West Washington Street
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