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BEFORE THE ARIZONA CORPORATION COMMISSION

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Commissioner  
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Commissioner  
BOB STUMP  
Commissioner

Arizona Corporation Commission

DOCKETED

JUN - 5 2009

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IN THE MATTER OF ARIZONA PUBLIC  
SERVICE COMPANY'S APPLICATION  
FOR APPROVAL OF A DEMAND  
RESPONSE PROGRAM )  
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)

DOCKET NO. E-01345A-08-0569

DECISION NO. 71104

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

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

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

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

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

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

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

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

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

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

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

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

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

21 20. **Real-Time Pricing** Real-Time Pricing ("RTP") programs utilize prices that  
22 fluctuate hourly with the commodity market for power. Utilities tend to post these prices on a day-  
23 ahead basis, and they are applied to a customer's usage. RTP appears to be less beneficial to APS  
24 customers than the two other Time-Differentiated Rate programs previously discussed (Super Peak  
25 and Critical Peak Pricing). APS will, however, continue to monitor industry experience in this  
26 area. RTP tends to be more expensive to implement and is better targeted to C&I customers who  
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28 <sup>1</sup> Docket No. E-01345A-08-0172

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

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

### 6 **III. Overview of Proposed C&I Program**

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

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

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

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

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

- 24 a) specific knowledge, resources, and systems that APS currently lacks,
- 25 b) assumption of all risks associated with customer performance, and
- 26 c) guaranteed load reductions when required, with payment only for verified  
27 reductions, and penalties for nonperformance.

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

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

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

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

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

#### 4 **IV. Benefit / Cost Analysis**

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

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

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

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

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

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

1 substantially less than the installed cost of a new unit.

## 2 V. Cost Recovery

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

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

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

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

## 21 VI. Eligibility

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

## 23 VII. Staff Recommendations

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

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

## 29 VIII. Additional Commission Findings

30 43. The Commission believes that several of the demand response programs not

1 selected by APS for inclusion in this Application may hold significant promise for benefiting both  
2 the Company and its customers. This is particularly the case with regard to the Vehicle to Grid  
3 program, in which utilities may eventually benefit from paying customers to plug their electric  
4 vehicles into the grid, allowing the utility to economically draw power at peak times of the day  
5 from the vehicles' batteries while they are parked. Accordingly to the APS Demand Response and  
6 Load Management Study, at least two other utilities in the West are examining this option, and one  
7 has entered into a partnership with Tesla Motors to conduct further testing on V2G. Moreover, the  
8 Study points out that while electric vehicles are not currently prevalent in the United States,  
9 several major automobile companies are planning to introduce electric vehicles by 2010 and  
10 Toyota has an electric vehicle commercially available in Japan.<sup>2</sup> Considering the likelihood that  
11 electric vehicles will emerge in the U. S. marketplace, and the potential benefits identified by APS,  
12 the Commission believes it is in the public interest for APS to conduct a V2G feasibility and cost  
13 benefit study and propose a V2G program for Commission consideration, no later than April 2,  
14 2010.

#### 15 CONCLUSIONS OF LAW

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

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

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

#### 23 ORDER

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

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28 <sup>2</sup> APS Demand Response and Load Management Study, pages 51-54.

1 IT IS FURTHER ORDERED that Arizona Public Service Company shall conduct a V2G  
2 feasibility and cost benefit study and file that study, as well as a proposed V2G program for the  
3 Commission's consideration, no later than April 2, 2010.

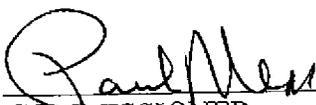
4 IT IS FURTHER ORDERED that program costs of the C&I Load Management Program  
5 be recovered by Arizona Public Service Company through the DSM adjustment mechanism,  
6 without any performance incentive.

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

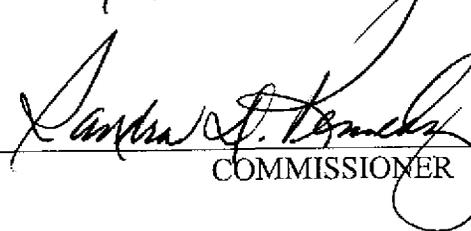
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9 **BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION**

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12 CHAIRMAN

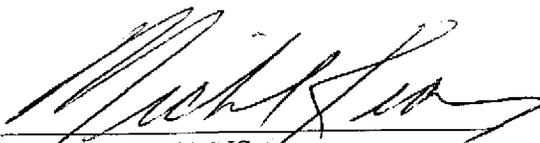
  
COMMISSIONER

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15 COMMISSIONER

  
COMMISSIONER

  
COMMISSIONER

16 IN WITNESS WHEREOF, I, MICHAEL P. KEARNS, Interim  
17 Executive Director of the Arizona Corporation Commission,  
18 have hereunto, set my hand and caused the official seal of this  
19 Commission to be affixed at the Capitol, in the City of  
20 Phoenix, this 5<sup>TH</sup> day of JUNE, 2009.

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22 MICHAEL P. KEARNS  
23 INTERIM EXECUTIVE DIRECTOR

24 DISSENT: \_\_\_\_\_

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26 DISSENT: \_\_\_\_\_

27 EGJ:JJP:lh\CH

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