Demand Response & Load Management Study

Overview of Research and Determinations

June 6, 2008

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Resource Acquisition
Topics for Discussion

- Reasons behind the Demand Response ("DR") Study
- DR Study overview
  - Quantitative evaluation approach
  - DR programs reviewed
  - Residential Survey results
  - Preliminary findings and results
  - C&I RFP Update
- Practical Application of DR
**Purpose of the Study**

- Preliminary review of the varying Demand Response programs that APS could implement
- Determines which ones make the most economic sense for APS and its customers
- Discussed internally since 2006 and subsequently required pursuant to ACC Decision No. 69663
  - Due to be filed by June 28, 2008
  - In addition, APS must also file one or more cost-effective programs for implementation
- Leveraged the experience of Summit Blue Consulting to research and analyze the different Demand Response programs available
What is Demand Response?

- Demand Response programs are mechanisms designed to provide incentives to customers to reduce their load in response to prices, market conditions, or threats to system reliability
  - ACC Decision No. 69663 at pp. 97-98 (June 28, 2007)
- Unlike Energy Efficiency, DR does not cause a permanent reduction in consumption

<table>
<thead>
<tr>
<th>Goals</th>
<th>Energy Efficiency</th>
<th>Demand Response</th>
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<tbody>
<tr>
<td></td>
<td>Permanent reduction in energy consumption</td>
<td>Reduce/shift consumption at times of system peak</td>
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<td></td>
<td>Reduced peak capacity need</td>
<td>Some programs may result in net reduction in consumption</td>
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</table>
Summer 2006 DR Participation at time of System Peaks – RTOs/ISOs

Federal Energy Regulatory Commission, 2007 Assessment of Demand Response and Advanced Metering, Derived from Table D-1 (September 2007).
Elements of the Study

- Executive Summary
- Overview/Objectives
- APS Situation Assessment
  - Load Shape / Demand Characteristics
  - Supply-side Resources
  - Base Case Forecast
  - Other Relevant Factors
  - Potential for DR on the APS System
- Evaluation Overview
  - Formulas
  - Estimated Emissions Impact
  - Items to Note
- Programs Details
  - Overview
  - Current Programs in Other Jurisdictions
  - Applicability to APS
  - Benefit/Cost and Emissions Impact Results (if applicable)
  - Recommendations
- Glossary
- References
Economic Test Overview – 3 Tests Utilized

- **G** = Generation Avoided Cost (Capacity & Energy)
- **T** = Transmission/Distribution Avoided Cost
- **E** = Environmental Benefits
- **R** = Rebate/Incentive Payments
- **PC_C** = Program Costs to Customer
- **PC_U** = Program Costs to Utility

**Total Resource Cost Test (“TRCT”)**
- **B_TRCT** = G + T
- **C_TRCT** = PC_C + PC_U
- **BCR_TRCT** = B_TRCT / C_TRCT

**Societal Cost Test** = TRCT + Environmental Benefits
- Quantified but not monetized

**Program Administrator Test**
- **B_PACT** = G + T
- **C_PACT** = PC_U + R
- **BCR_PACT** = B_PACT / C_PACT
Estimated Emissions Impact Calculation

- Goal – estimate the net emissions decrease/(increase) due to APS exercising certain DR programs
- On-peak assumption – Combustion Turbine is the unit “on the margin”
- Off-peak assumption – Combined Cycle is the unit “on the margin”
  - Based upon production simulations and the type of units likely to be running
- Example:
  - DR program provides for a 4 hour on-peak reduction in cooling demand, resulting in 400 MWh of reduced consumption after accounting for pre/post cooling (“Snapback Effect”)
  - Estimated Emissions Impact = Avoided emissions from 400 MWh of equivalent run time from a CT unit
# Programs Reviewed

<table>
<thead>
<tr>
<th>Direct Load Control</th>
<th>Customer Load Response</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential A/C Cycling</td>
<td>Curtailable/Interruptible Rates</td>
</tr>
<tr>
<td>Residential Misc. Load Control</td>
<td>Demand Bidding/Buyback</td>
</tr>
<tr>
<td>C&amp;I Load Control</td>
<td>Standby Generation</td>
</tr>
<tr>
<td></td>
<td>Plug-in Vehicles</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Scheduled Load Management</th>
<th>Time-Differentiated Rates</th>
</tr>
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<tbody>
<tr>
<td>Thermal Energy Storage</td>
<td>Time-of-Use Rates</td>
</tr>
<tr>
<td>Scheduled Water Pumping</td>
<td>Critical Peak Pricing</td>
</tr>
<tr>
<td>Battery Storage</td>
<td>Real-Time Pricing</td>
</tr>
</tbody>
</table>
Residential Survey Overview

- 1,000 residential low country customers owning single family homes
  - Evenly split between five rate plans
- The programs were described as running on no more than 20 summer afternoons (June – Sept) from 3-7pm
  - Free Thermostats – raise temperature no more than 4 degrees
  - A/C Switches – cycle 12 minutes out of every half hour (40% cycling strategy)
Results of the Residential Survey

- 14-17% of all residential customers expressed an interest in allowing APS to remotely cycle their A/C unit via either a thermostat or an A/C switch (depending on incentive level)
  - Equates to 25-30% of Low Country Single-Family Homeowners
  - If APS offered only one enabling technology:
    - Free thermostat – 11-13% total participation
    - A/C switch – 11-12% total participation
## Quantitative Results

<table>
<thead>
<tr>
<th>Program</th>
<th>Reduction per Participant</th>
<th>Estimated Number of Participants</th>
<th>Estimated MW Reduction</th>
<th>PAC Test</th>
<th>TRCT</th>
<th>CO₂ Decrease/Increase in tons</th>
<th>NOₓ Decrease/Increase in lbs</th>
<th>PM10 Decrease/Increase in lbs</th>
</tr>
</thead>
<tbody>
<tr>
<td>A/C DLC - 40% Cycling - Base Case</td>
<td>1.04 kW</td>
<td>65,000</td>
<td>68 MW</td>
<td>0.89</td>
<td>1.32</td>
<td>7,487</td>
<td>2,271</td>
<td>160</td>
</tr>
<tr>
<td>A/C DLC - 40% Cycling - Survey Results @ $25 Incentive</td>
<td>1.04 kW</td>
<td>127,800</td>
<td>133 MW</td>
<td>1.03</td>
<td>1.59</td>
<td>14,721</td>
<td>4,465</td>
<td>314</td>
</tr>
<tr>
<td>A/C DLC - 40% Cycling - Survey Results @ $50 Incentive</td>
<td>1.04 kW</td>
<td>153,000</td>
<td>159 MW</td>
<td>0.79</td>
<td>1.60</td>
<td>17,624</td>
<td>5,345</td>
<td>376</td>
</tr>
<tr>
<td>A/C+WH DLC - 40% Cycling - Base Case</td>
<td>1.28 kW</td>
<td>65,000 A/C 26,000 WH</td>
<td>74 MW</td>
<td>0.86</td>
<td>1.35</td>
<td>8,178</td>
<td>2,480</td>
<td>174</td>
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<tr>
<td>Small Scale TES</td>
<td>10 kW</td>
<td>Studied on a &quot;per participant&quot; basis</td>
<td>2.29</td>
<td>0.70</td>
<td>53</td>
<td>32</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Large Scale TES</td>
<td>200 kW</td>
<td></td>
<td></td>
<td>3.42</td>
<td>1.10</td>
<td>795</td>
<td>476</td>
<td>3</td>
</tr>
<tr>
<td>Standby Generation - $3.50/gallon Diesel</td>
<td>1,750 kW</td>
<td>29</td>
<td>50 MW</td>
<td>1.04</td>
<td>1.04</td>
<td>(10,855)</td>
<td>(406,493)</td>
<td>N/A</td>
</tr>
<tr>
<td>Standby Generation - $4.50/gallon Diesel</td>
<td>1,750 kW</td>
<td>29</td>
<td>50 MW</td>
<td>0.97</td>
<td>0.97</td>
<td>(10,855)</td>
<td>(406,493)</td>
<td>N/A</td>
</tr>
</tbody>
</table>

- Increasing the incentive from $25 per season to $50 per season for residential DLC participants has a no impact on the TRCT results, but a negative impact on the PAC Test results
  - Program assumes that the DR program is available 100 hours per year, and APS exercises 50% of the time
- The size of the TES unit can dictate whether or not it is cost effective for the consumer
  - Program assumes customer pays for the TES technology and APS provides a rebate for 50% of the costs
- The cost of diesel fuel dictates whether or not a Standby Generator program is cost effective from an economic screening standpoint
  - Because the program is capacity-based in nature, the cost of diesel fuel would not significantly change dispatch decisions if a program were implemented
- Most programs provide a net environmental benefit
  - Standby Generation is the exception, as the load responsibility is shifting from an APS-owned CT to a customer-owned diesel-powered generator
Preliminary Findings

- Programs for consideration:
  - C&I DLC
  - Residential DLC
  - Residential Super-Peak Rate
  - Commercial/Industrial/Irrigation Critical Peak Pricing pilot program

- Programs that need additional evaluation:
  - Scheduled Water Pumping
  - Standby Generation
  - Thermal Energy Storage
Preliminary Findings (cont’d)

- Programs to be monitored but not pursued at this time:
  - Battery Storage
  - Demand Bidding/Buyback
  - Plug-in Vehicles
  - Curtailable/Interruptible Rates
  - Real-Time Pricing
C&I Load Management RFP

- Targeted RFP issued on 10/25/07
- Similar to a capacity call option contract
- Proposals submitted in December 2007
  - Ramping to as much as 200 MW over 5 years
  - Program availability between 11am – 7pm
  - Maximum callable hour limit up to 100 hours per season
- Compared to a conventional supply-side resource
- Multiple companies with Benefit/Cost ratios >1.0 were short-listed
  - Contract negotiations on-going
Potential for Demand Response on the APS System

- Analyze the potential impacts of different DR strategies on APS system loads

- Data and assumptions
  - Summer only (Jun-Sept), max 90 hours
  - Four scenarios
    - 4x23 – four hour event, 23 highest peak load days
    - 5x18 – five hour event, 18 highest peak load days
    - 6x15 – six hour event, 15 highest peak load days
    - 7x13 – seven hour event, 13 highest peak load days
  - Analyses performed on actual APS historical data from 2002-2007

- Sensitivity #1 – 50% Snapback effect

- Sensitivity #2 – Missing 4th highest peak load day

- Applies to callable DR programs only
DR Potential – Results

- 52nd highest LDC hour is the new system peak, even though 90 hours of DR were purchased
  - 74 total hours out of the top 90 were effectively captured by this strategy
  - 376 MW reduction
    - Delta between 1st and 90th hour of the 2005 LDC is 481 MW
**DR Potential – Results (cont’d)**

- **Snapback Effect** sets a new peak hour outside of the targeted window, resulting in 125 MW less in experienced load reduction.
- MW amount varies by scenario.
Longer durations (6 hours per event vs. 4 hours per event) tend to result in larger MW potentials

- This implies that customers would be required to reduce load for longer periods of time on event days, which may limit the appeal of a DR program

A Snapback assumption of 50% greatly reduces the maximum DR potential in most cases

Failing to call on the DR resource on the 4th highest peak load day results in a fraction of the projected potential for the entire year (59 MW vs. 376 MW for 2005 6x15 scenario)

Callable DR resources provide value to APS

- Must understand the inherent limitations to maximize their value

**Summary of DR Potential Levels as a Percentage of Peak Demand**

<table>
<thead>
<tr>
<th>Base Case</th>
<th>4x23</th>
<th>5x18</th>
<th>6x15</th>
<th>7x13</th>
<th>AVG</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.4%</td>
<td>5.2%</td>
<td>6.8%</td>
<td>6.6%</td>
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<td>5.7%</td>
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<table>
<thead>
<tr>
<th>50% Snapback</th>
<th>4x23</th>
<th>5x18</th>
<th>6x15</th>
<th>7x13</th>
<th>AVG</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.9%</td>
<td>3.5%</td>
<td>5.0%</td>
<td>5.6%</td>
<td></td>
<td>4.3%</td>
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<table>
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<tr>
<th>Missing 4th Peak Day</th>
<th>4x23</th>
<th>5x18</th>
<th>6x15</th>
<th>7x13</th>
<th>AVG</th>
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<tr>
<td>1.9%</td>
<td>1.9%</td>
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Questions?