2010 Load Impact Evaluation of California's Statewide Base Interruptible Program (BIP)

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DRMEC Load Impact Workshop
San Francisco, CA
April 26, 2011

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Presentation Overview

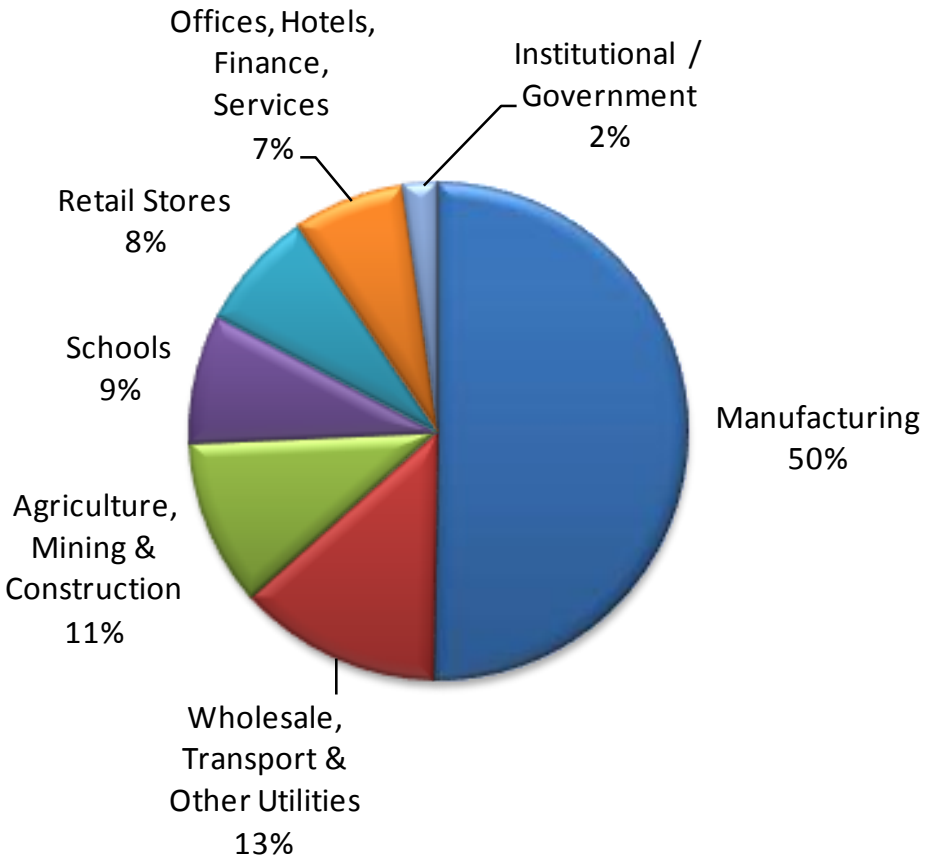
- Program Overview
- 2010 Ex Post Load Impact Estimates
  - August 24th PG&E Test Event
  - September 27th SDG&E Test Event
- 2011-2021 Ex Ante Load Impact Estimates
- Evaluation Methodology
- Regression Model Accuracy and Validation
- Recommendations

BIP Programs are Similar Across Utilities

- **Eligibility** – Committed load reduction must meet two requirements:
  - At least 100 kW
  - At least 15% of maximum demand
- **Incentive** – Monthly capacity credit based on difference between average peak period demand and firm service level (FSL)
- **Penalty** – Excess energy charges for failure to reduce load to FSL during events
- **Event trigger** – CAISO system emergency, local emergency or test
- **Notification lead time** – Most participants are enrolled in the 30-minute notification option
  - SCE – 89%
  - PG&E – 100%
  - SDG&E – 95%

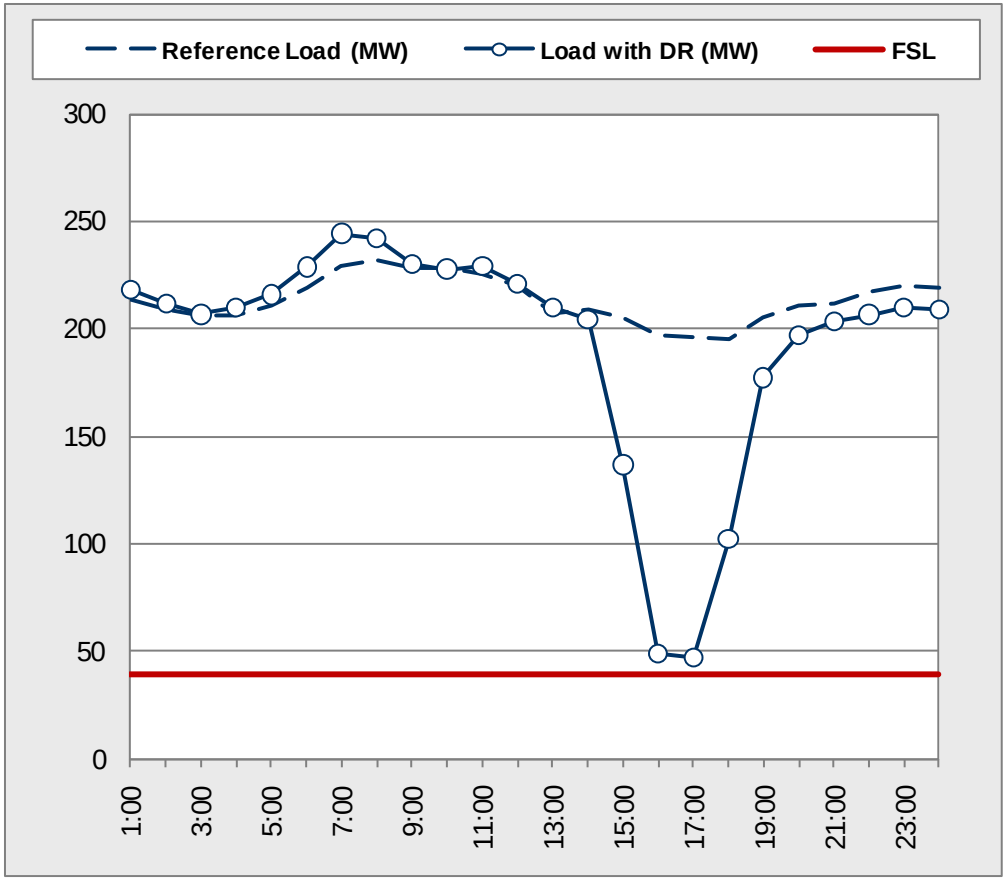
BIP Participation by Industry

- 836 enrolled accounts as of January 2011
  - **SCE:** 626 accounts
  - **PG&E:** 189 accounts
  - **SDG&E:** 21 accounts
- Half of participants come from the manufacturing sector, which may be because of the 100 kW load reduction commitment

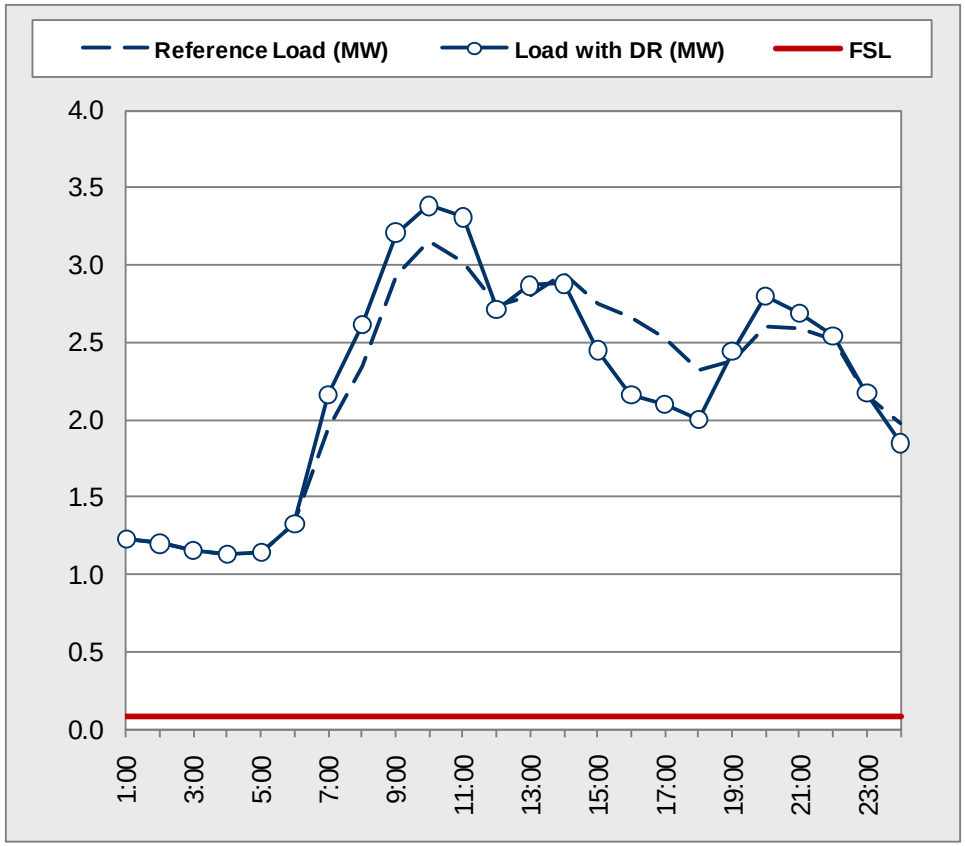


August 24, 2010 PG&E Test Event

- Lasted two hours, from 3 to 5 pm
- Included all 189 accounts that were enrolled at the time
- 788 kW average load reduction per customer during the event period
- 149 MW aggregate load reduction during the event period
- 76% load reduction relative to the reference load of 197 MW
- The event-period load of 48 MW was slightly higher than the aggregate FSL of 39 MW
- BIP customers slightly under performed, reducing load by roughly 5% less than what was required to meet their FSL commitments



September 27, 2010 SDG&E Test Event



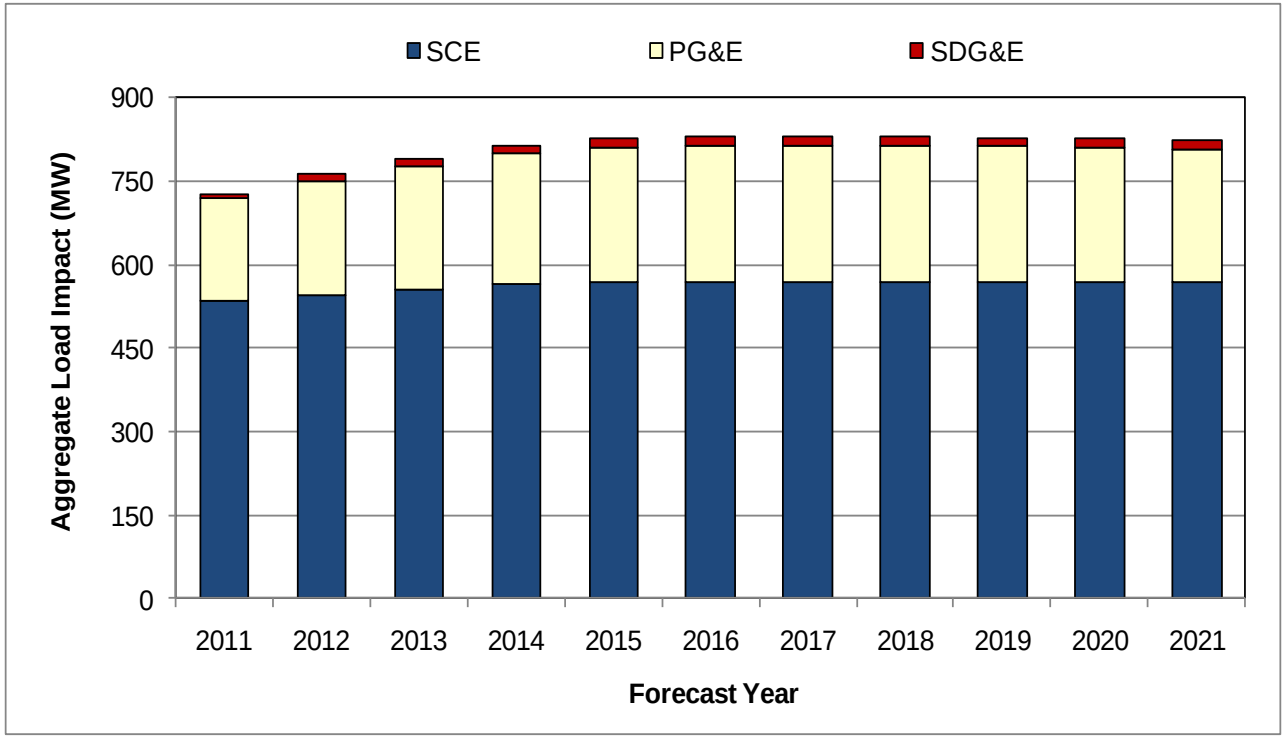
- 2-6 PM for BIP option A (12 accounts – first BIP event)
- 3-6 PM for BIP option B (1 account)
- BIP customers dually-enrolled in CPP were not required to respond to the BIP event because there was a CPP event on the same day (6 accounts)
- 32 kW average load reduction per customer from 3-6 PM
- 0.42 MW aggregate load reduction from 3-6 PM
- 17% load reduction relative to the reference load of 2.5 MW
- Aggregate load of 2.08 MW was substantially higher than the aggregate FSL of 0.08 MW
- Under performed during this event, providing only 17% of the 2.42 MW reduction that BIP customers needed in order to be in compliance

Key Assumptions in Ex Ante Analysis

- Performance relative to the FSL is similar to the recent past
  - Pooled 2006-2010 event data used for SCE and PG&E
  - For SDG&E, 2010 event was used
- Projected BIP enrollment
  - **SCE:** Considering that SCE is near its emergency cap allocation, BIP enrollment is estimated to remain constant throughout forecast period (2011-2021)
  - **PG&E:** Enrollment projected to grow to 267 accounts by 2021
  - **SDG&E:** Enrollment projected to increase to 55 accounts by May 2014 and then remains constant afterwards
- Effect of economic recovery on future BIP load
  - **SCE:** BIP load is assumed to increase by 1.5% per year from 2011 through 2014 and then reach a steady state from 2015 through 2021
  - **PG&E:** BIP load is also assumed to increase by 1.5% per year from 2011 through 2014 and then *decrease* by 0.6% per year from 2015 through 2021
  - **SDG&E:** BIP load is assumed to remain the same

2011-2021 Aggregate Load Impacts by Utility and Forecast Year

Typical Event Day in a 1-in-2 Weather Year



- For the typical event day in a 1-in-2 weather year, the program is projected to deliver 725 MW in 2011
- By 2014, the aggregate load impact is expected to grow by 12% to 815 MW
- From 2015 through 2021, the aggregate impact remains around 827 MW in each year (slight decrease because load decrease for PG&E)
- In each forecast year, around 68% to 74% of the aggregate load reduction comes from SCE, 25% to 30% from PG&E and the remaining 1% to 2% from SDG&E

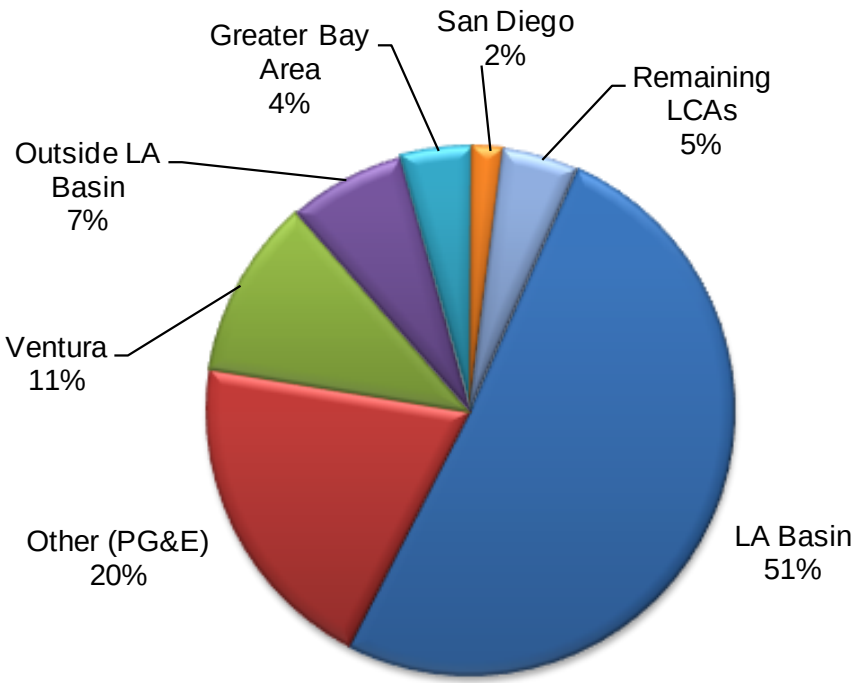
These results are not significantly different for 1-in-10 weather year conditions because BIP customers are not weather-sensitive on average

Distribution of 2015 Statewide Aggregate Load Impacts by Local Capacity Area

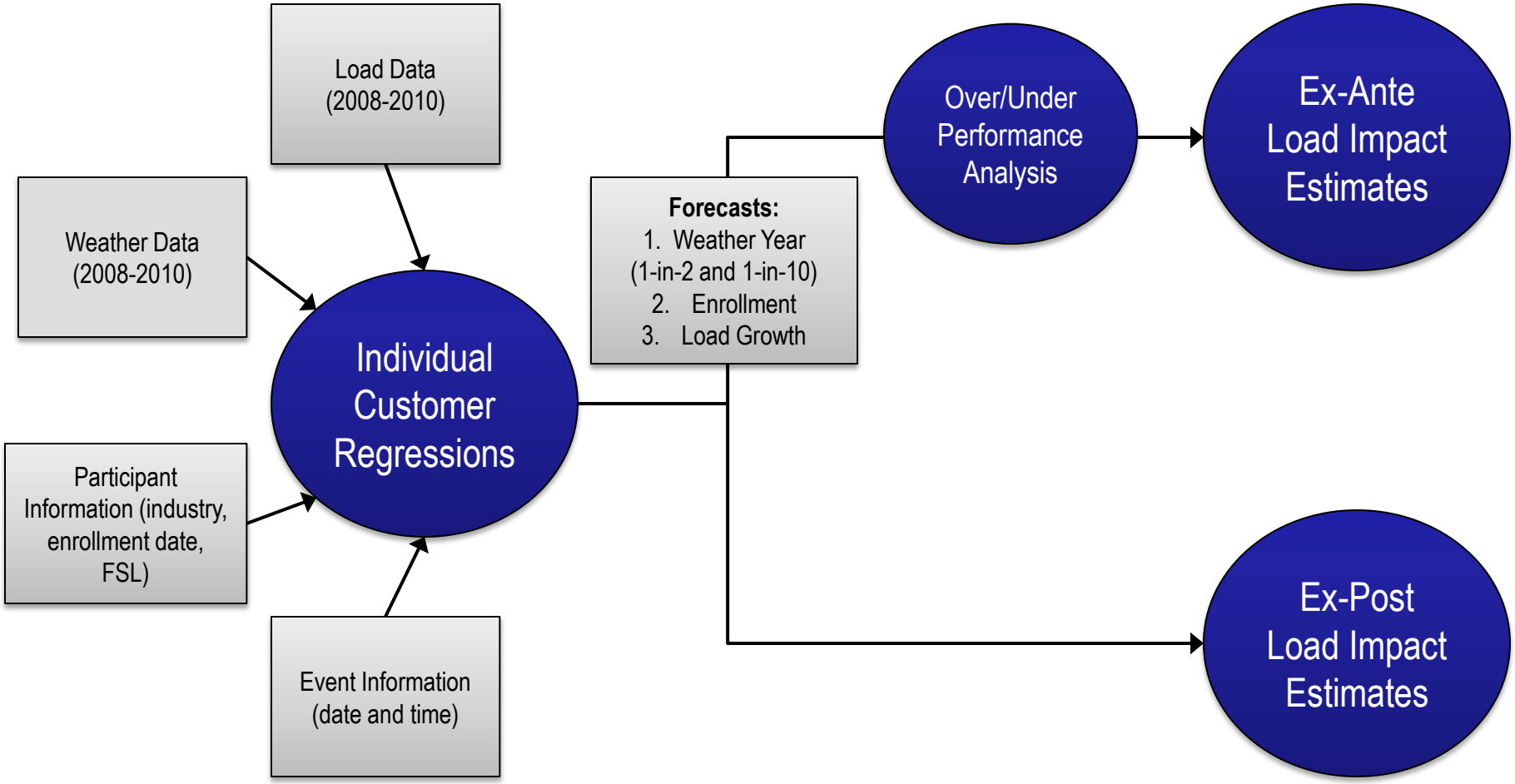
August Monthly Peak Day in a 1-in-2 Weather Year

- LCAs are CAISO-designated planning regions in which utilities must meet local resource adequacy requirements
- For the August monthly peak day in a 1-in-2 weather year in 2015, the statewide aggregate load impact is 818 MW
- The LA Basin LCA in SCE's service territory comprises 51% of the statewide aggregate load impact
- PG&E's Other LCA is the only area outside of SCE's territory that provides more than 4% of the statewide aggregate load impact.

Total Statewide Aggregate Impact = 818 MW



Evaluation Methodology



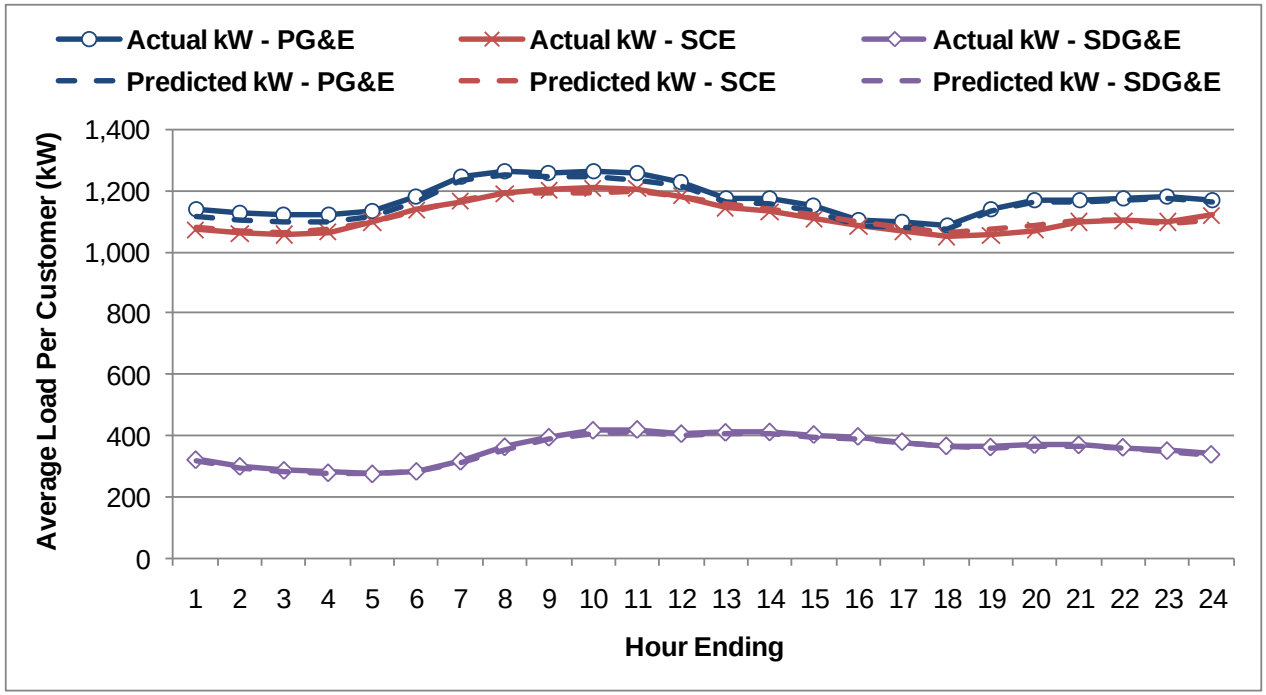
Regression Model Accuracy and Validation

- A number of out-of-sample validations were conducted
  - Rather than running the model on all of the available load data, a group of five randomly selected high temperature weekdays was withheld from the estimation database
  - Although these five days are not included in the estimating sample, the model is used to predict load on those days
  - This process is repeated three times so that out-of-sample predictions of load are generated for the top 15 maximum temperature weekdays for each customer
- This validation process most closely aligns with what is expected of the model in the ex post and ex ante analyses
  - In the ex ante analysis, the model is used to simulate the reference load and load with DR under 1-in-2 and 1-in-10 weather year scenarios
  - The ex post analysis estimates load reductions by predicting what load would have been if an event was not called
  - In both of these analyses, out-of-sample predictions are generated for scenarios in which actual, unperturbed load data is not available
  - Therefore, out-of-sample validation using randomly selected high temperature weekdays is a logical test to determine which model is most accurate
  - **Note:** Works well when numerous high temperature, *non-event* weekdays are available

Actual v. Predicted Average Load by Utility

Out-of-Sample Validation for Top 15 Maximum Temperature Weekdays

- Model accurately predicts load on high temperature weekdays even if those days are not included in the estimating sample
- The difference between actual and predicted load did not exceed 2.3% in any hour for each utility
- More importantly, percentage error is low during the afternoon, which is when events are most likely to be called
- Between 1 PM and 6 PM, the SCE model slightly over predicts by 1.2%, whereas the PG&E and SDG&E models under predict by less than 1.5%



Considering that BIP customers typically drop more than 70% of their load during events, an error of 1.2% to 1.5% will have little effect on the accuracy of the load impact estimates

Recommendations

- PG&E and SDG&E test events in 2010 significantly improved the quality of the ex ante estimates
- We recommend that PG&E and SDG&E continue to call annual test events and that SCE considers calling a test event in 2011
- When calling a test event, all utilities should consider the event conditions that they are attempting to simulate
  - If a BIP test event is meant to simulate a generation supply shortage, we recommend giving at least one day notice
  - If a BIP test event is meant to simulate a transmission or distribution outage, no advanced notice should be given
- With more events, SCE and PG&E may no longer need to pool event data in the ex ante analysis

For any questions, please contact…

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