JAMIE SCRIPPS

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PROFESSIONAL EXPERIENCE

5 Lakes Energy LLC
Partner
JULY 2012 – PRESENT (Lansing, MI)

- Co-owner of Michigan-based consulting firm offering services in advanced energy research, engagement, and advocacy.
- Lead Michigan-based education and engagement efforts related to combined heat and power (CHP) among a variety of stakeholders including end-users (commercial, industrial, institutional), utilities, trade associations, non-profit organizations, state policymakers and regulators, and other stakeholders.
- Provide expert research and analysis of standby rates of electric utilities.
- Direct and implement education and advocacy campaign related to advancing state-level policies in Michigan to encourage adoption of industrial energy efficiency, CHP, waste heat to power (WHP), and district energy technology applications.
- Lead contractor, researcher and project manager for state energy office grant project developing a roadmap for optimized deployment of CHP in Michigan.

Kaplan University
Academic Department Chair
AUGUST 2010 – JULY 2012

- Supervised and provided coaching to online faculty teaching in Master of Public Administration, MS in Legal Studies, and MS in Environmental Policy programs.
- Served as subject matter expert (SME) in development of curriculum for courses in public administration and environmental policy.

Michigan Department of Energy, Labor & Economic Growth
Assistant Deputy Director for Energy
FEBRUARY 2009 – JULY 2010 (Lansing, MI)

- On behalf of the state's Chief Energy Officer, assisted in hosting and facilitating engagement by a variety of stakeholders, including representatives from environmental groups, manufacturing associations, labor unions, utilities and ratepayers on the development of state-level clean energy policy and programs.
- Participated on the executive team strategically deploying energy-related stimulus funds through the state energy office, including weatherization, green schools, and the creation of the Michigan Saves energy efficiency financing program.
- Worked with legislature and regulators on implementation of utility energy efficiency programs.

Sondee, Racine & Doren, PLC
Associate Attorney
JANUARY 2008 – DECEMBER 2008 (Traverse City, MI)

- Practiced law at firm specializing in municipal law.
- Provided legal representation to clients such as the Grand Traverse County Brownfield Redevelopment Authority and Traverse City Light & Power.

Michigan Environmental Council
Deputy Policy Director
APRIL 2007 – DECEMBER 2007 (Lansing, MI)

- Researched and advocated before the state legislature on policy proposals related to CHP and WHP deployment, renewable energy standard, and utility energy efficiency programs.

Venable LLP
Associate Attorney
SEPTEMBER 2005 – MARCH 2007 (Washington, DC)

- Provided legal defense for shipping and manufacturing clients under investigation for federal environmental crimes.
- Supported legal representation of large investor-owned utility.
- Represented clients in civil litigation in Virginia and the District of Columbia, including extensive factual investigation related to energy and environmental matters.

EDUCATIONAL BACKGROUND

University of Michigan Law School – Ann Arbor, MI

- Juris Doctor awarded May 2005
  - Admitted: State Bar of Michigan, District of Columbia Bar, Virginia State Bar

North Central College – Naperville, IL

- Master's Degree in Leadership Studies awarded June 2002

University of Michigan School of Education – Ann Arbor, MI

- Bachelor's in Education (with honors) awarded May 1999

5 Lakes Energy "Apples to Apples" Standby Rate Analyses: Narrative Description with Calculations

Contents

DTE Energy – Proposed Rider 3

For the following calculations, we built off of Minnesota Power's billing simulations provided in their filing in Minnesota PUC Docket No. E-999/CI-15-115, and adapted each scenario for a General Service customer served at the Primary Distribution level.

For purposes of a comparable analysis of DTE Energy's Rider No. 3, we assumed a Primary Supply Rate (Schedule D11) customer with 3,000 kW in nominated standard service, 2,000 kW in reserved Standby Service.[1]

For each of the following scenarios, the Daily Demand Cap was calculated using the D11 Power Supply Demand Charge of 14.65 per kW of contracted standby capacity (2000 kW) for a total of

[1] For purposes of this analysis, we refer to "Standby Service" and not "Station Power Standby Service" as defined in Standard Contract Rider No. 3, Parallel Operation and Standby Service and Station Power Standby Service. "Standby Service" applies to customers with generation facilities that are located within retail service territory of DTE and are directly interconnected with DTE.

$29,300. The Daily On-Peak Backup Demand Charges do not exceed this maximum, so this figure does not apply.

In accordance with DTE's proposed changes to Rider 3, we calculated energy charges by aggregating the 'capacity' and 'non-capacity' elements listed in the tariff. The capacity component of the energy charge reads: "For customers served on supplemental rate schedules D4, D11, D6.2 and D8, the energy charge will be 1.724c per kWh, plus appropriate power supply credits, including but not limited to an off-peak credit of 1.00c per kWh…" The non-capacity section reads: "For customers served on supplemental rate schedules D4, D11, D6.2 and D8, the energy charge will be 2.606c per kWh…" In our analysis, we add these two components for an on-peak energy charge of 4.33c per kWh and an off-peak energy charge of 3.33c per kWh. We did not add power supply credits or costs.

Summary

No Outage = $11,955.00

Scheduled Outage 16 hours off-peak: $13,020.60

Scheduled Outage 16 hours on-peak: $20,880.60

Scheduled Outage 8 hours on-peak, 8 hours off-peak: $15,040.60

Scheduled Outage 32 hours on-peak: $33,626.20

Unscheduled Outage 8 hours on-peak, 8 hours off-peak: $19,400.60

No Outage

For the "no outage" calculation, we assumed an April peak load of 3,000 kW.

- With no outage and no standby service provided, the Reservation Fee would apply.
- DTE calculates the Reservation Fee as:

    Standby Reservation Rate * standby capacity reserved (kW)

    The Standby Reservation Rate is listed as $1.91/kW. The Standby Capacity reserved is 2,000 kW.

    Therefore, the Reservation Fee is calculated as:

    1.91 * 2,000 = $3,820.00

The Delivery Service Charge is $275/month and does not appear to be contingent on whether standby service is used.

The Distribution Charge is applied to total standby contract capacity, do does not appear to be contingent on whether standby service is used. Therefore, the Distribution Charge in this scenario would be calculated as:

3.93 * 2,000 = $7,860.00

Total “No Outage” Standby Bill = **$11,955.00**

Scheduled Outage – 16 hours off-peak

For this scheduled outage calculation, we assumed a complete 16-hour outage that took place during DTE’s peak window over two days (11 am to 7 pm) in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

    Standby Reservation Rate * standby capacity reserved (kW)

    The Standby Reservation Rate is listed as $1.91. The Standby Capacity reserved is 2,000 kW.

    Therefore, the Reservation Fee is calculated as:

    1.91 * 2,000 = $3,820.00

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, the Reservation Fee is waived.
- There are no Daily On-Peak Back-Up Demand Charges because the outage takes place during off-peak times.
- Therefore, the reservation fee applies.
- Energy charges are calculated using the Off-Peak Energy Charge Rate of 3.33 cents/kWh of standby power used.
- The outage lasted 16 hours and used 2,000 kW of capacity. Therefore, 32,000 kWh were used.
- Energy charges for this outage scenario would be calculated as:

0.0333 * 32,000 = 1,065.60

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.93/kW of standby capacity used.

3.93 * 2,000 = 7,860.00

Total Standby Charges = $13,020.60

Scheduled Outage – 16 hours on-peak

For this scheduled outage calculation, we assumed a complete 16-hour outage that took place during DTE's peak window over two days (11 am to 7 pm) in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

  Standby Reservation Rate * standby capacity reserved (kW)

  The Standby Reservation Rate is listed as $1.91. The Standby Capacity reserved is 2,000 kW.

  Therefore, the Reservation Fee is calculated as:

  1.91 * 2,000 = $3,820

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, the Reservation Fee is waived.
- The "maintenance" or Scheduled rate for Daily On-Peak Back-Up Demand Charges is 2.84.
- Daily On-Peak Back-Up Demand Charges are calculated as:

Daily On-Peak Back-Up Demand Charges Maintenance Rate * kW of standby capacity used * number of days of outage

Therefore, the calculation would be:

2.84 * 2,000 * 2 = 11,360.00

- Because Daily On-Peak Back-Up Demand Charges total more than the Reservation Fee, the Reservation Fee is waived.
- Energy charges are calculated using the On-Peak Energy Charge Rate of 4.33 cents/kWh of standby power used.
- The outage lasted 16 hours and used 2,000 kW of capacity. Therefore, 32,000 kWh were used.
- Energy charges for this outage scenario would be calculated as:

0.0433 * 32,000 = 1,385.60

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.93/kW of standby capacity used.

3.93 * 2,000 = 7,860.00

Total Standby Charges = $20,880.60

Scheduled Outage – 8 hours on-peak, 8 hours off-peak

For this scheduled outage calculation, we assumed a complete 16-hour outage, 8 hours of which took place during DTE's peak window (11 am to 7 pm) over one day in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

  Standby Reservation Rate * standby capacity reserved (kW)

  The Standby Reservation Rate is listed as $1.91. The Standby Capacity reserved is 2,000 kW.

  Therefore, the Reservation Fee is calculated as:

  1.91 * 2,000 = $3,820.00

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, than the Reservation Fee is waived.
- The "maintenance" or Scheduled rate for Daily On-Peak Back-Up Demand Charges is 2.84.
- Daily On-Peak Back-Up Demand Charges are calculated as:

Daily On-Peak Back-Up Demand Charges Maintenance Rate * kW of standby capacity used * number of days of outage

Therefore, the calculation would be:

2.84 * 2,000 * 1 = 5,680.00

- Because Daily On-Peak Back-Up Demand Charges total more than the Reservation Fee, the Reservation Fee is waived.
- Energy charges are calculated using the On-Peak Energy Charge Rate of 4.33 cents/kWh and Off-Peak Energy Charge Rate of 3.33 cents/kWh of standby power used.
- The outage lasted 16 hours and used 2,000 kW of capacity; 8 hours were on-peak and 8 hours were off-peak. Therefore, 16,000 kWh were on-peak and 16,000 kWh were off-peak.
- Energy charges for this outage scenario would be calculated as:

0.0433 * 16,000 = 692.80

0.0333 * 16,000 = 532.80

Total Energy Charges = 1,225.60

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.93/kW of standby capacity used.

3.93 * 2,000 = 7,860.00

Total Standby Charges = **$15,040.60**

Scheduled Outage – 32 hours on-peak

For this scheduled outage calculation, we assumed a complete 32-hour outage that took place during DTE's peak window over four days (11 am to 7 pm) in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

  Standby Reservation Rate * standby capacity reserved (kW)

  The Standby Reservation Rate is listed as $1.91. The Standby Capacity reserved is 2,000 kW.

  Therefore, the Reservation Fee is calculated as:

  1.91 * 2,000 = $3,820.00

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, the Reservation Fee is waived.
- The "maintenance" or Scheduled rate for Daily On-Peak Back-Up Demand Charges is 2.84.
- Daily On-Peak Back-Up Demand Charges are calculated as:

Daily On-Peak Back-Up Demand Charges Maintenance Rate * kW of standby capacity used * number of days of outage

Therefore, the calculation would be:

2.84* 2,000 * 4 = 22,720.00

- Because Daily On-Peak Back-Up Demand Charges total more than the Reservation Fee, the Reservation Fee is waived.
- Energy charges are calculated using the On-Peak Energy Charge Rate of 4.33 cents/kWh of standby power used.
- The outage lasted 32 hours and used 2,000 kW of capacity. Therefore, 64,000 kWh were used.

- Energy charges for this outage scenario would be calculated as:

0.0433 * 64,000 = 2,771.00

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.93/kW of standby capacity used.

3.93 * 2,000 = 7,860.00

Total Standby Charges = **$33,626.20**

Unscheduled Outage

For this unscheduled outage calculation, we assumed a complete 16-hour outage, 8 hours of which took place during DTE's peak window (11 am to 7 pm) over one day in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

  Standby Reservation Rate * standby capacity reserved (kW)

  The Standby Reservation Rate is listed as $1.91. The Standby Capacity reserved is 2,000 kW.

  Therefore, the Reservation Fee is calculated as:

  1.91 * 2,000 = $3,820.00

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, the Reservation Fee is waived.
- The non-maintenance or Unscheduled rate for Daily On-Peak Back-Up Demand Charges is 5.02.
- Daily On-Peak Back-Up Demand Charges are calculated as:

Daily On-Peak Back-Up Demand Charges Non-Maintenance Rate * kW of standby capacity used * number of days of outage

Therefore, the calculation would be:

5.02 * 2,000 * 1 = 10,040.00

- Because Daily On-Peak Back-Up Demand Charges total more than the Reservation Fee, the Reservation Fee is waived.

- Energy charges are calculated using the On-Peak Energy Charge Rate of 4.33 cents/kWh and the Off-Peak Energy Charge Rate of 3.33 cents/kWh of standby power used.
- The outage lasted 16 hours and used 2,000 kW of capacity; 8 hours were on-peak and 8 hours were off-peak. Therefore, 16,000 kWh were on-peak and 16,000 kWh were off-peak.
- Energy charges for this outage scenario would be calculated as:

0.0433 * 16,000 = 692.80

0.0333 * 16,000 = 532.80

Total Energy Charges = 1,225.60

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.93/kW of standby capacity used.

3.93 * 2,000 = 7,860.00

Total Standby Charges = **$19,400.60**

DTE Energy – Rider 3 currently in effect

For the following calculations, we built off of Minnesota Power's billing simulations provided in their filing in Minnesota PUC Docket No. E-999/CI-15-115, and adapted each scenario for a General Service customer served at the Primary Distribution level.

For purposes of a comparable analysis of DTE Energy's Rider No. 3, we assumed a Primary Supply Rate (Schedule D11) customer with 3,000 kW in nominated standard service, 2,000 kW in reserved Standby Service.[2]

For each of the following scenarios, the Daily Demand Cap was calculated using the D11 Power Supply Demand Charge of 14.65 per kW of contracted standby capacity (2000 kW) for a total of $29,300. The Daily On-Peak Backup Demand Charges do not exceed this maximum, so this figure does not apply.

Summary

No Outage = $10,535.00

Scheduled Outage 16 hours off-peak: $11,657

Scheduled Outage 16 hours on-peak: $18,653.24

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[2] For purposes of this analysis, we refer to "Standby Service" and not "Station Power Standby Service" as defined in Standard Contract Rider No. 3, Parallel Operation and Standby Service and Station Power Standby Service. "Standby Service" applies to customers with generation facilities that are located within retail service territory of DTE and are directly interconnected with DTE.

Scheduled Outage 8 hours on-peak, 8 hours off-peak: $13,405.24

Scheduled Outage 32 hours on-peak: $30,271.48

Unscheduled Outage 8 hours on-peak, 8 hours off-peak: $17,545.24

No Outage

For the “no outage” calculation, we assumed an April peak load of 3,000 kW.

- With no outage and no standby service provided, the Reservation Fee would apply.
- DTE calculates the Reservation Fee as:

  Standby Reservation Rate * standby capacity reserved (kW)

  The Standby Reservation Rate is listed as $1.75. The Standby Capacity reserved is 2,000 kW.

  Therefore, the Reservation Fee is calculated as:

  1.75 * 2000 = $3,500

The Delivery Service Charge is $275/month and does not appear to be contingent on whether standby service is used.

The Distribution Charge is applied to total standby contract capacity, do does not appear to be contingent on whether standby service is used. Therefore, the Distribution Charge in this scenario would be calculated as:

3.38 * 2000 = 6760.00

Total “No Outage” Standby Bill = **$10,535.00**

Scheduled Outage – 16 hours off-peak

For this scheduled outage calculation, we assumed a complete 16-hour outage that took place during DTE’s peak window over two days (11 am to 7 pm) in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

  Standby Reservation Rate * standby capacity reserved (kW)

  The Standby Reservation Rate is listed as $1.75. The Standby Capacity reserved is 2,000 kW.

  Therefore, the Reservation Fee is calculated as:

1.75 * 2000 = $3,500

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, the Reservation Fee is waived.
- There are no Daily On-Peak Back-Up Demand Charges because the outage takes place during off-peak times.
- Therefore, the reservation fee applies.
- Energy charges are calculated using the Schedule D11 On-Peak Energy Charge Rate of 3.507 cents/kWh of standby power used.
- The outage lasted 16 hours and used 2,000 kW of capacity. Therefore, 32,000 kWh were used.
- Energy charges for this outage scenario would be calculated as:

0.03807 * 32,000 = 1112.24

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.38/kW of standby capacity used.

3.38 * 2000 = 6,760

Total Standby Charges = $18,653.24

Scheduled Outage – 16 hours on-peak

For this scheduled outage calculation, we assumed a complete 16-hour outage that took place during DTE's peak window over two days (11 am to 7 pm) in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

  Standby Reservation Rate * standby capacity reserved (kW)

  The Standby Reservation Rate is listed as $1.75. The Standby Capacity reserved is 2,000 kW.

  Therefore, the Reservation Fee is calculated as:

  1.75 * 2000 = $3,500

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, the Reservation Fee is waived.
- The "maintenance" or Scheduled rate for Daily On-Peak Back-Up Demand Charges is 2.60.

- Daily On-Peak Back-Up Demand Charges are calculated as:

Daily On-Peak Back-Up Demand Charges Maintenance Rate * kW of standby capacity used * number of days of outage

Therefore, the calculation would be:

2.60 * 2000 * 2 = 10,400

- Because Daily On-Peak Back-Up Demand Charges total more than the Reservation Fee, the Reservation Fee is waived.
- Energy charges are calculated using the Schedule D11 On-Peak Energy Charge Rate of 3.807 cents/kWh of standby power used.
- The outage lasted 16 hours and used 2,000 kW of capacity. Therefore, 32,000 kWh were used.
- Energy charges for this outage scenario would be calculated as:

0.03807 * 32,000 = 1,218

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.38/kW of standby capacity used.

3.38 * 2000 = 6,760

Total Standby Charges = $18,653.24

Scheduled Outage – 8 hours on-peak, 8 hours off-peak

For this scheduled outage calculation, we assumed a complete 16-hour outage, 8 hours of which took place during DTE's peak window (11 am to 7 pm) over one day in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

  Standby Reservation Rate * standby capacity reserved (kW)

  The Standby Reservation Rate is listed as $1.75. The Standby Capacity reserved is 2,000 kW.

  Therefore, the Reservation Fee is calculated as:

  1.75 * 2000 = $3,500

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, than the Reservation Fee is waived.

- The “maintenance” or Scheduled rate for Daily On-Peak Back-Up Demand Charges is 2.60.
- Daily On-Peak Back-Up Demand Charges are calculated as:

Daily On-Peak Back-Up Demand Charges Maintenance Rate * kW of standby capacity used * number of days of outage

Therefore, the calculation would be:

2.60 * 2000 * 1 = 5,200

- Because Daily On-Peak Back-Up Demand Charges total more than the Reservation Fee, the Reservation Fee is waived.
- Energy charges are calculated using the Schedule D11 On-Peak Energy Charge Rate of 3.807 cents/kWh and Off-Peak Energy Charge Rate of 3.507 cents/kWh of standby power used.
- The outage lasted 16 hours and used 2,000 kW of capacity; 8 hours were on-peak and 8 hours were off-peak. Therefore, 16,000 kWh were on-peak and 16,000 kWh were off-peak.
- Energy charges for this outage scenario would be calculated as:

0.03807 * 16,000 = 609.12

0.03507 * 16,000 = 561.12

Total Energy Charges = 1,170

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.38/kW of standby capacity used.

3.38 * 2000 = 6,760

Total Standby Charges = **$13,405.24**

Scheduled Outage – 32 hours on-peak

For this scheduled outage calculation, we assumed a complete 32-hour outage that took place during DTE’s peak window over four days (11 am to 7 pm) in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

Standby Reservation Rate * standby capacity reserved (kW)

The Standby Reservation Rate is listed as $1.75. The Standby Capacity reserved is 2,000 kW.

Therefore, the Reservation Fee is calculated as:

1.75 * 2000 = $3,500

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, the Reservation Fee is waived.
- The "maintenance" or Scheduled rate for Daily On-Peak Back-Up Demand Charges is 2.60.
- Daily On-Peak Back-Up Demand Charges are calculated as:

Daily On-Peak Back-Up Demand Charges Maintenance Rate * kW of standby capacity used * number of days of outage

Therefore, the calculation would be:

2.60* 2000 * 4 = 20,800

- Because Daily On-Peak Back-Up Demand Charges total more than the Reservation Fee, the Reservation Fee is waived.
- Energy charges are calculated using the Schedule D11 On-Peak Energy Charge Rate of 3.807 cents/kWh of standby power used.
- The outage lasted 32 hours and used 2,000 kW of capacity. Therefore, 64,000 kWh were used.
- Energy charges for this outage scenario would be calculated as:

0.03807 * 64,000 = 2,436

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.38/kW of standby capacity used.

3.38 * 2000 = 6,760

Total Standby Charges = **$30,271.48**

Unscheduled Outage

For this unscheduled outage calculation, we assumed a complete 16-hour outage, 8 hours of which took place during DTE's peak window (11 am to 7 pm) over one day in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

Standby Reservation Rate * standby capacity reserved (kW)

The Standby Reservation Rate is listed as $1.75. The Standby Capacity reserved is 2,000 kW.

Therefore, the Reservation Fee is calculated as:

1.75 * 2000 = $3,500

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, the Reservation Fee is waived.
- The non-maintenance or Unscheduled rate for Daily On-Peak Back-Up Demand Charges is 4.67.
- Daily On-Peak Back-Up Demand Charges are calculated as:

Daily On-Peak Back-Up Demand Charges Non-Maintenance Rate * kW of standby capacity used * number of days of outage

Therefore, the calculation would be:

4.67 * 2000 * 1 = 9,340

- Because Daily On-Peak Back-Up Demand Charges total more than the Reservation Fee, the Reservation Fee is waived.
- Energy charges are calculated using the Schedule D11 On-Peak Energy Charge Rate of 3.807 cents/kWh of standby power used.
- The outage lasted 16 hours and used 2,000 kW of capacity; 8 hours were on-peak and 8 hours were off-peak. Therefore, 16,000 kWh were on-peak and 16,000 kWh were off-peak.
- Energy charges for this outage scenario would be calculated as:

0.03807 * 16,000 = 609.12

0.03507 * 16,000 = 561.12

Total Energy Charges = 1,170

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.38/kW of standby capacity used.

3.38 * 2000 = 6,760

Total Standby Charges = **$17,545.24**

DTE Energy – Proposed Rider 3 (70%)

For the following calculations, we built off of Minnesota Power's billing simulations provided in their filing in Minnesota PUC Docket No. E-999/CI-15-115, and adapted each scenario for a General Service customer served at the Primary Distribution level.

For purposes of a comparable analysis of DTE Energy's Rider No. 3, we assumed a Primary Supply Rate (Schedule D11) customer with 3,000 kW in supplemental service and a 2,000 kW CHP system.

It was pointed out in a Standby Rate Working Group meeting by representatives from DTE that its use of the 1001st highest half-hourly kW output in determining standby contract capacity can result in a number that is up to 30% less than nameplate capacity. Therefore, standby contract capacity is assumed to be 1,400 kW.

For each of the following scenarios, the Daily Demand Cap was calculated using the D11 Power Supply Demand Charge of 14.65 per kW of contracted standby capacity (1400 kW) for a total of $20,510. The Daily On-Peak Backup Demand Charges do not exceed this maximum, so this figure does not apply.

In accordance with DTE's proposed changes to Rider 3, we calculated energy charges by aggregating the 'capacity' and 'non-capacity' elements listed in the tariff. The capacity component of the energy charge reads: "For customers served on supplemental rate schedules D4, D11, D6.2 and D8, the energy charge will be 1.724c per kWh, plus appropriate power supply credits, including but not limited to an off-peak credit of 1.00c per kWh…" The non-capacity section reads: "For customers served on supplemental rate schedules D4, D11, D6.2 and D8, the energy charge will be 2.606c per kWh…" In our analysis, we add these two components for an on-peak energy charge of 4.33c per kWh and an off-peak energy charge of 3.33c per kWh. We did not add power supply credits or costs.

Summary

No Outage = $8,451.00

Scheduled Outage 16 hours off-peak: $9,190.20

Scheduled Outage 16 hours on-peak: $14,698.92

Scheduled Outage 8 hours on-peak, 8 hours off-peak: $10,610.92

Scheduled Outage 32 hours on-peak: $23,620.84

Unscheduled Outage 8 hours on-peak, 8 hours off-peak: $13,662.92

No Outage

For the "no outage" calculation, we assumed an April peak load of 3,000 kW.

- With no outage and no standby service provided, the Reservation Fee would apply.
- DTE calculates the Reservation Fee as:

    Standby Reservation Rate * standby capacity reserved (kW)

    The Standby Reservation Rate is listed as $1.91. The Standby Capacity reserved is 1,400 kW.

    Therefore, the Reservation Fee is calculated as:

    1.91 * 1,400 = $2,674.00

The Delivery Service Charge is $275/month and does not appear to be contingent on whether standby service is used.

The Distribution Charge is applied to total standby contract capacity, do does not appear to be contingent on whether standby service is used. Therefore, the Distribution Charge in this scenario would be calculated as:

3.93 * 1,400 = 5,502.00

Total “No Outage” Standby Bill = **$8,451.00**

Schedule Outage – 16 hours off-peak

For this scheduled outage calculation, we assumed a complete 16-hour outage that took place during DTE’s off-peak window over two days in April.[3] We are still assuming 3,000 kW in supplemental service and 1,400 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

    Standby Reservation Rate * standby capacity reserved (kW)

    The Standby Reservation Rate is listed as $1.91. The Standby Capacity reserved is 1,400 kW.

    Therefore, the Reservation Fee is calculated as:

    1.91 * 1400 = $2,674.00

- If total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, the Reservation Fee is waived.
- In this scenario, the customer is able to avoid using any standby capacity during on-peak times. Therefore, there are no on-peak backup demand charges.

[3] A Scheduled 16-hour outage could begin at 7 pm and last for 16 hours before the next on-peak window started at 11 am the next day, but the outage would still span 2 days.

- Therefore, the Reservation Fee would apply instead of Daily On-Peak Back-Up Demand Charges.
- Energy charges are calculated using the Off-Peak Energy Charge Rate of 4.33 cents/kWh of standby power used.
- The outage lasted 16 hours and used 1,400 kW of capacity. Therefore, 22,400 kWh were used.
- Energy charges for this outage scenario would be calculated as:

0.0333 * 22,400 = 739.00

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.93/kW of standby capacity used.

3.93 * 1,400 = 5,502.00

Total Standby Charges = **$9,190.00**

Scheduled Outage – 16 hours on-peak

For this scheduled outage calculation, we assumed a complete 16-hour outage that took place during DTE's peak window over two days (11 am to 7 pm) in April. We are still assuming 3,000 kW in standard nominated service and 1,400 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

    Standby Reservation Rate * standby capacity reserved (kW)

    The Standby Reservation Rate is listed as $1.91. The Standby Capacity reserved is 1,400 kW.

    Therefore, the Reservation Fee is calculated as:

    1.91 * 1,400 = $2,674.00

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, the Reservation Fee is waived.
- The "maintenance" or Scheduled rate for Daily On-Peak Back-Up Demand Charges is 2.84.
- Daily On-Peak Back-Up Demand Charges are calculated as:

Daily On-Peak Back-Up Demand Charges Maintenance Rate * kW of standby capacity used * number of days of outage

Therefore, the calculation would be:

2.84 * 1,400 * 2 = 7,952.00

- Because Daily On-Peak Back-Up Demand Charges total more than the Reservation Fee, the Reservation Fee is waived.
- Energy charges are calculated using the On-Peak Energy Charge Rate of 4.33 cents/kWh of standby power used.
- The outage lasted 16 hours and used 1,400 kW of capacity. Therefore, 22,400 kWh were used.
- Energy charges for this outage scenario would be calculated as:

0.0433 * 22,400 = 969.92

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.93/kW of standby capacity used.

3.93 * 1,400 = 5,502.00

Total Standby Charges = $**14,698.92**

Scheduled Outage – 8 hours on-peak, 8 hours off-peak

For this scheduled outage calculation, we assumed a complete 16-hour outage, 8 hours of which took place during DTE's peak window (11 am to 7 pm) over one day in April. We are still assuming 3,000 kW in standard nominated service and 1,400 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

    Standby Reservation Rate * standby capacity reserved (kW)

    The Standby Reservation Rate is listed as $1.91. The Standby Capacity reserved is 1,400 kW.

    Therefore, the Reservation Fee is calculated as:

  1.91 * 1,400 = $2,674

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, than the Reservation Fee is waived.
- The "maintenance" or Scheduled rate for Daily On-Peak Back-Up Demand Charges is 2.84.
- Daily On-Peak Back-Up Demand Charges are calculated as:

Daily On-Peak Back-Up Demand Charges Maintenance Rate * kW of standby capacity used * number of days of outage

Therefore, the calculation would be:

2.84 * 1,400 * 1 = 3,976

- Because Daily On-Peak Back-Up Demand Charges total more than the Reservation Fee, the Reservation Fee is waived.
- Energy charges are calculated using the On-Peak Energy Charge Rate of 4.33 cents/kWh and Off-Peak Energy Charge Rate of 3.33 cents/kWh of standby power used.
- The outage lasted 16 hours and used 1,400 kW of capacity; 8 hours were on-peak and 8 hours were off-peak. Therefore, 11,200 kWh were on-peak and 11,200 kWh were off-peak.
- Energy charges for this outage scenario would be calculated as:

0.0433 * 11,200 = 484.96

0.0333 * 11,200 = 372.96

Total Energy Charges = 857.92

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.93/kW of standby capacity used.

3.93 * 1,400 = 5,502.00

Total Standby Charges = **$10,610.92**

Scheduled Outage – 32 hours on-peak

For this scheduled outage calculation, we assumed a complete 32-hour outage that took place during DTE's peak window over four days (11 am to 7 pm) in April. We are still assuming 3,000 kW in standard nominated service and 1,400 kW in reserved standby capacity.

- As above, the Reservation Fee is calculated as:

  Standby Reservation Rate * standby capacity reserved (kW)

  The Standby Reservation Rate is listed as $1.91. The Standby Capacity reserved is 1,400 kW.

  Therefore, the Reservation Fee is calculated as:

  1.91 * 1,400 = $2,674.00
- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, the Reservation Fee is waived.

- The "maintenance" or Scheduled rate for Daily On-Peak Back-Up Demand Charges is 2.84.
- Daily On-Peak Back-Up Demand Charges are calculated as:

Daily On-Peak Back-Up Demand Charges Maintenance Rate * kW of standby capacity used * number of days of outage

Therefore, the calculation would be:

2.84* 1,400 * 4 = 15,904.00

- Because Daily On-Peak Back-Up Demand Charges total more than the Reservation Fee, the Reservation Fee is waived.
- Energy charges are calculated using the On-Peak Energy Charge Rate of 4.33 cents/kWh of standby power used.
- The outage lasted 32 hours and used 1,400 kW of capacity. Therefore, 44,800 kWh were used.
- Energy charges for this outage scenario would be calculated as:

0.0433 * 44,800 = 1,939.84

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.93/kW of standby capacity used.

3.93 * 1,400 = 5,502.00

Total Standby Charges = **$23,620.84**

Unscheduled Outage

For this unscheduled outage calculation, we assumed a complete 16-hour outage, 8 hours of which took place during DTE's peak window (11 am to 7 pm) over one day in April. We are still assuming 3,000 kW in standard nominated service and 1,400 kW in reserved standby capacity.

As above, the Reservation Fee is calculated as:

> Standby Reservation Rate * standby capacity reserved (kW)
>
> The Standby Reservation Rate is listed as $1.91. The Standby Capacity reserved is 1,400 kW.
>
> Therefore, the Reservation Fee is calculated as:

1.91 * 1,400 = $2,674.00

- However, if total Daily On-Peak Back-Up Demand Charges are more than the Reservation Fee, the Reservation Fee is waived.
- The non-maintenance or Unscheduled rate for Daily On-Peak Back-Up Demand Charges is 5.02.
- Daily On-Peak Back-Up Demand Charges are calculated as:

Daily On-Peak Back-Up Demand Charges Non-Maintenance Rate * kW of standby capacity used * number of days of outage

Therefore, the calculation would be:

5.02 * 1,400 * 1 = 7,028.00

- Because Daily On-Peak Back-Up Demand Charges total more than the Reservation Fee, the Reservation Fee is waived.
- Energy charges are calculated using the On-Peak Energy Charge Rate of 4.33 cents/kWh of standby power used.
- The outage lasted 16 hours and used 1,400 kW of capacity; 8 hours were on-peak and 8 hours were off-peak. Therefore, 11,200 kWh were on-peak and 11,200 kWh were off-peak.
- Energy charges for this outage scenario would be calculated as:

0.0433 * 11,200 = 484.96

0.0333 * 11,200 = 372.96

Total Energy Charges = 857.92

- In addition to demand and energy charges, there would be a Delivery Service Charge of $275/month.
- Also, there would be a Distribution Charge of $3.93/kW of standby capacity used.

3.93 * 1,400 = 5,502.00

Total Standby Charges = **$13,662.92**

Consumers Energy - Rate GSG-2

For the following calculations, we built off of Minnesota Power's billing simulations provided in their filing in Minnesota PUC Docket No. E-999/CI-15-115, and adapted each scenario for a General Service customer served at the Primary Distribution level (here, Customer Voltage Level 3).

We assumed a customer with 3,000 kW in standard service, 2,000 kW in reserved standby service, and that the customer was served at the primary distribution level.

For purposes of calculating the customer's Standby Demand, we will rely on the highest 15 minute kW demand, and will assume that there has been no Standby Demand usage for the previous 11 months. The Power Factor for all scenarios is assumed to be 0.90. It is further assumed that neither the Substation Ownership Credit nor the Transmission Interconnect Credit apply.

Rates for Power Supply Capacity, Power Supply Energy, and Delivery Capacity were revised to include explanations provided in Consumers Energy's comments received on 10/18/16 and 1/27/17.

*Note that a customer would not be able to reasonably estimate its Standby Bill without access to an estimate or forecast of the following:

1. The highest price of contracted capacity purchased by the Company in that month;
2. Costs related to Transmission and Ancillaries;
3. The MISO Real-Time Locational Market Price (LMP) for the Company's load node.

Summary

No Outage = $8300

Scheduled Outage 16 hours off-peak: $9246

Scheduled Outage 16 hours on-peak: $11,645

Scheduled Outage 8 hours on-peak, 8 hours off-peak: $11,191

Scheduled Outage 32 hours on-peak: $14,833

Unscheduled Outage 8 hours on-peak, 8 hours off-peak: $11,191

No Outage

The Company defines "Standby Demand" as:

> *the greater of the (i) highest 15 minute kW demand the Company supplies the customer for Standby Service during the current month or (ii) highest Standby Demand from the previous 11 months. The Company shall determine the amount of monthly Standby Demand supplied to the customer based upon the total amount of power supplied to the customer, their contract Standby Capacity and generator output.*

In the case of no outage, the Minimum Charge would apply.

The Company defines the Minimum Charge as:

> *The System Access Charge included in this Rate Schedule in addition to the customer's contracted Standby Capacity multiplied by the net of any Substation Ownership Credit and Delivery Capacity Charges of this Rate Schedule.*

The Delivery Capacity Charges for Customer Voltage Level 3 would be calculated as:

2,000 * 4.05 = $8,100

The System Access Charge for a Generator that does not meet or exceed load is $100/month.

There is a $100/month charge for the generator meter.

There are no Power Supply Capacity or Energy Charges in a “no outage” scenario.

Total “No Outage” Standby Bill = **$8300.00**

Scheduled Outage – 16 hours off-peak

For this scheduled outage calculation, we assumed a complete 16-hour outage that took place during Consumer’s Energy’s off-peak window over two days in March.

The Delivery Capacity Charges for Customer Voltage Level 3 would be calculated as:

2,000 * 4.05 = $8,100

The System Access Charge for a Generator that does not meet or exceed load is $100/month.

There is a $100/month generator meter charge.

There are no Power Supply Capacity charges because the outage takes place during off-peak times.

Power Supply Energy Charges are based on the spreadsheet sent by Consumers Energy on 1/26/17:

Total Energy Charges = $946

Total Standby Charges = **$9246**

Scheduled Outage – 16 hours on-peak

Note: There is no difference between a Scheduled and Unscheduled outage under Consumers Energy’s Standby Tariff.

For this scheduled outage calculation, we assumed a complete 16-hour outage that took place during Consumer’s Energy’s peak window over two days (11 am to 7 pm) in March, per comments received from the Company. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

The Delivery Capacity Charges for Customer Voltage Level 3 would be calculated as:

2,000 * 4.05 = $8,100

The System Access Charge for a Generator that does not meet or exceed load is $100/month.

There is a $100/month generator meter charge.

Power Supply Capacity Charges are calculated as:

> On Peak Capacity x (1 + Voltage 3 losses) x Standby Power Capacity Charge for the month x (# on peak days/total on peak days)
>
> 2000*1.05448*11.64*(2/22) = 2231.66

Power Supply Energy Charges are based on the spreadsheet sent by Consumers Energy on 10/18:

> In general: Sum [On Peak Capacity x (1 + Voltage 3 losses) x (LMP / 1000 + Market Settlement Fee)]
>
> In this case: Sum [2,000 kW x (1 + Voltage 1 losses) x (LMP / 1000 + $0.002/kWh)]
>
> =1112.90

Total Standby Charges = **$11,644.56**

Scheduled Outage – 8 hours on-peak, 8 hours off-peak

Note: There is no difference between a Scheduled and Unscheduled outage under Consumers Energy's Standby Tariff.

The differences here would show up in Power Supply Capacity Charges and Power Supply Energy Charges.

Power Supply Capacity Charges are calculated as:

> On Peak Capacity x (1 + Voltage 1 losses) x Standby Power Capacity Charge for the month x (# on peak days/total on peak days)
>
> 2000*1.05448*11.64*(1/22) = 1116.00

Power Supply Energy Charges are based on the spreadsheet sent by Consumers Energy on 10/18:

In general: Sum [On Peak Capacity x (1 + Voltage 1 losses) x (LMP / 1000 + Market Settlement Fee)]

In this case: Sum [2,000 kW x (1 + Voltage 1 losses) x (LMP / 1000 + $0.002/kWh)]

= 1775.00

Therefore, the total for a 16-hour scheduled outage in which 8 hours were on-peak and 8 hours were off-peak, would still be **$11,191.**

Scheduled Outage – 32 hours on-peak

Note: There is no difference between a Scheduled and Unscheduled outage under Consumers Energy's Standby Tariff.

For this scheduled outage calculation, we assumed a 32-hour outage that took place during Consumers Energy's peak window over four days in March. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

The Delivery Capacity Charges for Customer Voltage Level 3 would be calculated as:

2,000 * 4.05 = $8,100

The System Access Charge for a Generator that does not meet or exceed load is $100/month.

Power Supply Capacity Charges are calculated as:

On Peak Capacity x (1 + Voltage 1 losses) x Standby Power Capacity Charge for the month x (# on peak days/total on peak days)

2000*1.05448*11.64*(4/22) = 4463.00

Power Supply Energy Charges are based on the spreadsheet sent by Consumers Energy on 10/18:

In general: Sum [On Peak Capacity x (1 + Voltage 1 losses) x (LMP / 1000 + Market Settlement Fee)]

In this case: Sum [2,000 kW x (1 + Voltage 1 losses) x (LMP / 1000 + $0.002/kWh)]

=2070.00

Total Standby Charges = **$14,833**

Unscheduled Outage

Note: There is no difference between a Scheduled and Unscheduled outage under Consumers Energy's Standby Tariff.

Therefore, the total for a 16-hour unscheduled outage in which 8 hours were on-peak and 8 hours were off-peak, would still be **$11,191**

Upper Peninsula Power Company

UPPCO provides standby service to customers per the applicable rate schedule for the customer's full requirements service from the company. We assume a combined heat and power customer would take service under the Cp-U rate schedule for Large Commercial and Industrial customers[4] at a primary voltage distribution level.

Broadly speaking, standby service customers are charged the standard rate, with some modifications.

Under UPPCO's application of standby provisions, in calculating demand charges, hourly outages are rounded up to the day – so all of the outages in this analysis would end up being interpreted as taking place during on-peak times (even the Scheduled 16-hour "off peak" outage). On-peak demand charges are prorated according to the number of days in which standby service is taken.

We assume the customer contracts for 3,000 in normal capacity, 2,000 kW of standby capacity and takes service at the Primary voltage level. Primary voltage is provided at between 6,000 and 15,000 volts. UPPCO's on-peak period is from 7:00am-11:00pm, Monday through Friday. All outages are assumed to take place in April.

Summary

No outage: $0

Scheduled, 16 hours, off-peak: $2911

Scheduled, 16 hours, on-peak: $3883

Scheduled, 8 hours on-peak, 8 hours off-peak: $3397

Scheduled, 32 hours on-peak: $7766

Unscheduled, 8 hours on-peak, 8 hours off-peak: $31,631

[4] http://www.uppco.com/wp-content/uploads/UD2-D25.10-Large-C-I-Cp-U.pdf

No Outage

During the "No Outage" scenario, the customer responsible for charges related to normal demand. If the customer demand plus on-peak demand charges (for distribution and capacity) are greater than the standby minimum, then there are no additional standby charges.

In this case, the standby minimum is calculated as the maximum capacity needed when standby is included, so 3,000 kW plus 2,000 kW = 5,000 kW

This is multiplied by $2.75/kW

5000 * 2.75 = $13,750.

This number is compared to the total of:

Customer demand = 5850

On-peak demand (distribution) = 6180

On-peak demand (power supply) = 31,980

Total = 44,010

Because this total exceeds the standby minimum of $13,750, there are no additional charges to reserve standby in a "no outage" month.

(Note that there is no additional service fee, distribution fee or reservation attributable to standby service.)

Scheduled Outage, 16 hours off-peak

For calculation of demand charges, hourly outages are rounded up to the day. Therefore, this outage scenario would be interpreted as a one-day outage that happened during peak times. Energy charges are still calculated by the hour.

The customer would be responsible for the extra kWh needed due to the outage – in this case, off-peak energy charged at the off-peak rate:

0.05642 * 32,000 kWh = $1805

There is also a pro-rated demand charge for on-peak capacity used during the outage.

This is calculated using the following formula:

On Peak Demand Charge * (Number of Approved Nonholiday Weekdays in Billing Cycle/Number of Nonholiday Weekdays in Billing Cycle)

The normal on-peak demand charges are as follows:

Distribution = 2.06

Power Supply = 10.66

Total Normal Demand Charge = 12.72

The number of monthly peak days is estimated to be 23. The number of waiver/outage days under this scenario is 1.

12.72 * (1/23) = 0.553

This is then multiplied by the standby capacity used, or 2000 kW.

0.553 * 2000 = 1106.08

The pro-rated demand charge for this outage is 1106.08.

The total of energy and pro-rated demand charges for the outage would be: **$2911.08.**

(Note that there is no additional service fee, distribution fee or reservation attributable to standby service.)

Scheduled Outage, 16 hours on-peak

For calculation of demand charges, hourly outages are rounded up to the day. Therefore, this outage scenario would be interpreted as a one-day outage that happened during peak times. Energy charges are still calculated by the hour.

The customer would be responsible for the extra kWh needed due to the outage – in this case, on-peak energy charged at the on-peak rate:

0.08678 * 32,000 kWh = $2777

There is also a pro-rated demand charge for on-peak capacity used during the outage.

This is calculated using the following formula:

On Peak Demand Charge * (Number of Approved Nonholiday Weekdays in Billing Cycle/Number of Nonholiday Weekdays in Billing Cycle)

The normal on-peak demand charges are as follows:

Distribution = 2.06

Power Supply = 10.66

Total Normal Demand Charge = 12.72

The number of monthly peak days is estimated to be 23. The number of waiver/outage days under this scenario is 1.

12.72 * (1/23) = 0.553

This is then multiplied by the standby capacity used, or 2000 kW.

0.553 * 2000 = 1106.08

The pro-rated demand charge for this outage is 1106.08.

The total of energy and pro-rated demand charges for the outage would be: **$3883.08.**

(Note that there is no additional service fee, distribution fee or reservation attributable to standby service.)

Scheduled Outage 8 hours on-peak, 8 hours off-peak

For calculation of demand charges, hourly outages are rounded up to the day. Therefore, this outage scenario would be interpreted as a one-day outage that happened during peak times. Energy charges are still calculated by the hour.

The customer would be responsible for the extra kWh needed due to the outage – in this case, 8 hours of on-peak energy charged at the on-peak rate, and : 8 hours of off-peak energy charged at the off-peak rate

0.08678 * 16,000 kWh = $1388

0.05642 * 16,000 kWh = $903

Total energy charges = $2291

There is also a pro-rated demand charge for on-peak capacity used during the outage.

This is calculated using the following formula:

On Peak Demand Charge * (Number of Approved Nonholiday Weekdays in Billing Cycle/Number of Nonholiday Weekdays in Billing Cycle)

The normal on-peak demand charges are as follows:

Distribution = 2.06

Power Supply = 10.66

Total Normal Demand Charge = 12.72

The number of monthly peak days is estimated to be 23. The number of waiver/outage days under this scenario is 1.

12.72 * (1/23) = 0.553

This is then multiplied by the standby capacity used, or 2000 kW.

0.553 * 2000 = 1106.08

The pro-rated demand charge for this outage is 1106.08.

The total of energy and pro-rated demand charges for the outage would be: **$3397.08.**

(Note that there is no additional service fee, distribution fee or reservation attributable to standby service.)

Scheduled Outage, 32 hours on-peak

For calculation of demand charges, hourly outages are rounded up to the day. Therefore, this outage scenario would be interpreted as a two-day outage that happened during peak times. Energy charges are still calculated by the hour.

The customer would be responsible for the extra kWh needed due to the outage – in this case, on-peak energy charged at the on-peak rate:

0.08678 * 64,000 kWh = $5554

There is also a pro-rated demand charge for on-peak capacity used during the outage.

This is calculated using the following formula:

On Peak Demand Charge * (Number of Approved Nonholiday Weekdays in Billing Cycle/Number of Nonholiday Weekdays in Billing Cycle)

The normal on-peak demand charges are as follows:

Distribution = 2.06

Power Supply = 10.66

Total Normal Demand Charge = 12.72

The number of monthly peak days is estimated to be 23. The number of waiver/outage days under this scenario is 2.

12.72 * (2/23) = 1.106

This is then multiplied by the standby capacity used, or 2000 kW.

1.106 * 2000 = 2212.17

The pro-rated demand charge for this outage is 2212.17

The total of energy and pro-rated demand charges for the outage would be: **$7766.17.**

(Note that there is no additional service fee, distribution fee or reservation attributable to standby service.)

Unscheduled Outage, 8 hours on-peak, 8 hours off-peak

If an outage is not scheduled ahead of time, the pro-rated demand formula does not apply.

Instead, the total of a customer's "normal" customer demand is considered to be increased by the extra demand needed to cover the CHP outage. In this case, the normal demand would increase from 3,000 kW to 5,000 kW.

There would be extra energy charges associated with the outage (similar to the scheduled outage above):

0.08678 * 16,000 kWh = $1388

0.05642 * 16,000 kWh = $903

Total energy charges = $2291

The real difference is in the demand charges, which are not pro-rated. In order to calculate the increase attributable to the CHP system outage, I subtracted the normal demand charges (calculated using a normal customer demand of 3,000 kW) from the revised demand charges that are calculated using a customer demand of 5,000 kW.

<u>Customer Demand</u>

Normal Customer Demand Charge: 3,000 kW * 1.95 = 5850

Revised Customer Demand Charge with Standby = 5,000 kW * 1.95 = 9750

Difference attributable to CHP outage = $3900

<u>On-Peak Demand (Distribution)</u>

Normal On-Peak Demand (Distribution) Charge: 3,000 kW * 2.06 = 6180
Revised On-Peak Demand (Distribution) Charge with Standby = 5,000 kW * 2.06 = 10,300
Difference attributable to CHP outage = $4120

<u>On-Peak Demand (Power Supply)</u>

Normal On-Peak Demand (Power Supply) Charge: 3,000 kW * 10.66 = 31,980
Revised On-Peak Demand (Power Supply) Charge with Standby = 5,000 kW * 10.66 = 53,300
Difference attributable to CHP outage = $21,320

Total Difference in Demand Charges = $29,340

Therefore, the total of energy and demand charges for an unscheduled outage is: **$31,631.**

(Note that there is no additional service fee, distribution fee or reservation attributable to standby service.)

Upper Michigan Energy Resources Corporation

For the following calculations, we use Upper Michigan Energy Resources Corporation's (UMERC) current rate book.[5] UMERC does not have a designated standby service rate schedule, rather it includes standby provisions for existing customer classes.

We assume the customer takes service under the Large Commercial & Industrial Service (Cp-1M) rate schedule and takes service at the Primary voltage level between 4,160 and 69,000 volts.[6] In all scenarios, we assume the customer has contracted for 3,000 of normal service and 2,000 kW of standby demand.

Under this rate schedule, UMERC allows customers contracting for standby service to schedule preapproved maintenance outages with as much advance notice as possible. Maintenance periods are referred to as "waiver days" and are granted on a conditional basis by UMERC.

UMERC's peak periods vary by season. The outage scenarios in this analysis are assumed to occur in April. In winter (Oct-May), peak hours for demand are from 10:00am-8:00pm. For energy charges, winter peak hours are from 6:00am-10:00pm.

Summary

No outage: $0

Scheduled, 16 hours, off-peak: $2218

Scheduled, 16 hours, on-peak: $3098

Scheduled, 8 hours on-peak, 8 hours off-peak: $2658

Scheduled, 32 hours on-peak: $6196

Unscheduled, 8 hours on-peak, 8 hours off-peak: $30,536

No Outage

During the "No Outage" scenario, the customer would be responsible for charges related to normal demand. If the customer demand plus on-peak demand charges (for distribution and capacity) are greater than the standby minimum, then there are no additional standby charges.

In this case, the standby minimum is calculated as the maximum capacity needed when standby is included, so 3,000 kW plus 2,000 kW = 5,000 kW

This is multiplied by $2.75/kW

[5] http://www.uppermichiganenergy.com/rates/umerc-electric-rates.pdf

[6] At the primary distribution level, there are three voltage options: <4,160 volts, >4,160 to <69,000 volts, and >69,000 volts.

5000 * 2.75 = $13,750.

This number is compared to the total of:

Customer demand = 6660

On-peak demand (distribution) = 3420

On-peak demand (power supply) = 33,510

Total = 43,590

Because this total exceeds the standby minimum of $13,750, there are no additional charges to reserve standby in a "no outage" month.

(Note that there is no additional service fee, distribution fee or reservation attributable to standby service.)

Scheduled Outage 16 hours off-peak

For calculation of demand charges, hourly outages are rounded up to the day. Therefore, this outage scenario would be interpreted as a one-day outage that happened during peak times. Energy charges are still calculated by the hour.

The customer would be responsible for the extra kWh needed due to the outage – in this case, off-peak energy charged at the off-peak rate:

0.03237 * 32,000 kWh = $1036

There is also a pro-rated demand charge for on-peak capacity used during the outage.

This is calculated using the following formula:

(Total Normal On-Peak Demand Charge * 12 months / No. of annual peak days) * No. of outage days

The normal on-peak demand charges are as follows:

Distribution = 1.14

Power Supply = 11.17

Total Normal Demand Charge = 12.31

The number of annual peak days is estimated to be 250. The number of waiver/outage days under this scenario is 1.

12.31 * (12 / 250) * 1 * 2,000 = 1181.76

Therefore, the pro-rated demand charge is 1181.76.

The total of energy and pro-rated demand charges for the outage would be: **$2217.76**

(Note that there is no additional service fee, distribution fee or reservation attributable to standby service.)

Scheduled Outage 16 hours on-peak

For calculation of demand charges, hourly outages are rounded up to the day. Therefore, this outage scenario would be interpreted as a one-day outage that happened during peak times. Energy charges are still calculated by the hour.

The customer would be responsible for the extra kWh needed due to the outage – in this case, on-peak energy charged at the on-peak rate:

0.05987 * 32,000 kWh = $1916

There is also a pro-rated demand charge for on-peak capacity used during the outage.

This is calculated using the following formula:

(Total Normal On-Peak Demand Charge * 12 months / No. of annual peak days) * No. of outage days

The normal on-peak demand charges are as follows:

Distribution = 1.14

Power Supply = 11.17

Total Normal Demand Charge = 12.31

The number of annual peak days is estimated to be 250. The number of waiver/outage days under this scenario is 1.

12.31 * (12 / 250) * 1 * 2,000 = 1181.76

Therefore, the pro-rated demand charge is 1181.76.

The total of energy and pro-rated demand charges for the outage would be: **$3097.76.**

Scheduled Outage 8 hours on-peak/8 hours off-peak

For calculation of demand charges, hourly outages are rounded up to the day. Therefore, this outage scenario would be interpreted as a one-day outage that happened during peak times. Energy charges are still calculated by the hour.

The customer would be responsible for the extra kWh needed due to the outage – in this case, 8 hours of on-peak energy charged at the on-peak rate, and 8 hours of off-peak energy charged at the off-peak rate :

0.03237 * 16,000 kWh = 518

0.05987 * 16,000 kWh = 958

Total energy charges = $1476

There is also a pro-rated demand charge for on-peak capacity used during the outage.

This is calculated using the following formula:

(Total Normal On-Peak Demand Charge * 12 months / No. of annual peak days) * No. of outage days

The normal on-peak demand charges are as follows:

Distribution = 1.14

Power Supply = 11.17

Total Normal Demand Charge = 12.31

The number of annual peak days is estimated to be 250. The number of waiver/outage days under this scenario is 1.

12.31 * (12 / 250) * 1 * 2,000 = 1181.76

Therefore, the pro-rated demand charge is 1181.76.

The total of energy and pro-rated demand charges for the outage would be: **$2657.76**

(Note that there is no additional service fee, distribution fee or reservation attributable to standby service.)

Scheduled Outage 32 hours on-peak

For calculation of demand charges, hourly outages are rounded up to the day. Therefore, this outage scenario would be interpreted as a two-day outage that happened during peak times. Energy charges are still calculated by the hour.

The customer would be responsible for the extra kWh needed due to the outage – in this case, on-peak energy charged at the on-peak rate:

0.05987 * 64,000 kWh = $3832

There is also a pro-rated demand charge for on-peak capacity used during the outage.

This is calculated using the following formula:

(Total Normal On-Peak Demand Charge * 12 months / No. of annual peak days) * No. of outage days

The normal on-peak demand charges are as follows:

Distribution = 1.14

Power Supply = 11.17

Total Normal Demand Charge = 12.31

The number of annual peak days is estimated to be 250. The number of waiver/outage days under this scenario is 2.

12.31 * (12 / 250) * 2 * 2,000 = 2363.52

Therefore, the pro-rated demand charge is 2363.52

The total of energy and pro-rated demand charges for the outage would be: **$6195.52**

(Note that there is no additional service fee, distribution fee or reservation attributable to standby service.)

Unscheduled Outage 8 hours on-peak, 8 hours off-peak

If an outage is not scheduled ahead of time, the pro-rated demand formula does not apply.

Instead, the total of a customer's "normal" customer demand is considered to be increased by the extra demand needed to cover the CHP outage. In this case, the normal demand would increase from 3,000 kW to 5,000 kW.

There would be extra energy charges associated with the outage (similar to the scheduled outage above):

0.03237 * 16,000 kWh = 518

0.05987 * 16,000 kWh = 958

Total energy charges = $1476

The real difference is in the demand charges, which are not pro-rated.

In order to calculate the increase attributable to the CHP system outage, I subtracted the normal demand charges (calculated using a normal customer demand of 3,000 kW) from the revised demand charges that are calculated using a customer demand of 5,000 kW.

<u>Customer Demand</u>

Normal Customer Demand Charge: 3,000 kW * 2.22 = 6660

Revised Customer Demand Charge with Standby = 5,000 kW * 2.22 = 11,100

Difference attributable to CHP outage = $4440

<u>On-Peak Demand (Distribution)</u>

Normal On-Peak Demand (Distribution) Charge: 3,000 kW * 1.14 = 3420

Revised On-Peak Demand (Distribution) Charge with Standby = 5,000 kW * 1.14 = 5700

Difference attributable to CHP outage = $2280

<u>On-Peak Demand (Power Supply)</u>

Normal On-Peak Demand (Power Supply) Charge: 3,000 kW * 11.17 = 33,510

Revised On-Peak Demand (Power Supply) Charge with Standby = 5,000 kW * 11.17 = 55,850

Difference attributable to CHP outage = $22,340

Total Difference in Demand Charges = $29,060

Therefore, the total of energy and demand charges for an unscheduled outage is: **$30,536**

(Note that there is no additional service fee, distribution fee or reservation attributable to standby service.)

Minnesota Power

For the following calculations, we built off of Minnesota Power's billing simulations provided in their filing, and adapted each scenario for a General Service customer served at the Primary Distribution level. This analysis has been further revised to reflect clarifications provided in Minnesota Power's Response to Fresh Energy Information Request #6, Docket No. E-999/CI-15-115.

We assumed a General Service customer with 3,000 kW in nominated standard service, 2,000 kW in reserved standby service, and that the customer was served at the primary distribution level.

For calculation of the Standby Reservation Fee, we used a 5% forced outage rate.[7]

Summary:[8]

No Outage = $1007.00 (Standby Reservation Fee)

Scheduled Outage 16 hours off-peak: $2699.16

Scheduled Outage 16 hours on-peak: $2699.16

Scheduled Outage 8 hours on-peak, 8 hours off-peak: $2699.16

Scheduled Outage 32 hours on-peak: $4391.32

Unscheduled Outage 8 hours on-peak, 8 hours off-peak: $20,180 plus hourly incremental energy costs

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[7] Forced outage rates experienced by combined heat and power (CHP) systems are approximately 5% overall, with 2.5% during peak periods. See "Distributed Generation Operational Reliability and Availability Database," 2004, https://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/dg_operational_final_report.pdf.

[8] These calculations do not include applicable adjustments on the energy portion for the Renewable Resource Adjustment, Transmission Adjustment, Boswell 4 Plan Adjustment, Rider for Conservation Program Adjustment and Rider for Fuel and Purchased Energy Adjustment.

No Outage

For the "no outage" calculation, we assumed an April peak load of 3,000 kW.

- For standby charges, only the Standby Reservation Fee would apply. Minnesota Power calculates this as:

  Standby Reservation Rate * standby capacity reserved (kW) * forced outage rate

  The Standby Reservation Rate for Primary Distribution Level service is listed in their filing as 10.07 (Exhibit A, page 4 of 15). Standby capacity reserved is 2,000 kW. FOR is .05%.

  10.07*2,000*.05= $1007.00

Total "No Outage" Standby Bill = **$1007.00**

Scheduled Outage – 16 hours off-peak

For this scheduled outage calculation, we assumed a 16-hour outage that took place during Minnesota Power's off-peak window during two days in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Standby Reservation Fee is calculated as:

  Standby Reservation Rate * standby capacity reserved (kW) * forced outage rate

  The Standby Reservation Rate for Primary Distribution Level service is listed in their filing as 10.07 (Exhibit A, page 4 of 15). Standby capacity reserved is 2,000 kW. FOR is 5%.

  10.07*2,000*.05= $1007.00

- Due to the outage, the customer may be responsible for standby demand charges, depending on whether they exceed the Standby Reservation Fee.
- In order to calculate Standby Demand Charges during a scheduled outage, we first have to calculate the Standby Billing Demand.
- Per the company's filing: "To determine the standby billing demand, the measured demand will be multiplied by the number of days the Scheduled Outage lasts during the month and divided by the number of days in the billing month." (Exhibit A, page 5)
- Here, we have 2,000 kW in standby capacity used for two days of outage divided by 30 days in April. This yields a Standby Billing Demand of 133.33.

- Standby Demand Charges are calculated by multiplying the Standby Billing Demand by the standard rate schedule. The standard rate for General Service served at the Primary Distribution Level is $5.86/kW, minus a $1.75/kW discount for taking primary distribution service. This yields a standard rate of $4.11/kW (see Rate Book, section V, page 10.1)

  Standby Demand Charges: 133.33 * $4.11=$547.99

  Here, the Standby Reservation Fee is greater, so the customer would pay the reservation fee instead of the demand charges.

Energy Charges

The customer would also be responsible for the energy used during the outage, per their standard rate schedule.

The standard energy charge for a General Service customer in the Minnesota Power Electric Rate Book, section V, page 10.1 is 5.288 cents/kWh.

In a 16 hour outage using 2,000 kW of standby capacity, total kWh would be 32,000.

0.05288*32000 = 1692.16

Total Energy Charges: $1692.16

When the energy charges are added to the Standby Reservation Fee, the total expected standby bill is **$2699.16**.

Scheduled Outage – 16 hours on-peak

Note: Per the company's filing, a customer is permitted to schedule an outage that falls during peak times, as long as the outage is to fall in a shoulder month and proper notice is provided.

For this scheduled outage calculation, we assumed a 16-hour outage that took place during Minnesota Power's peak window during one day (6 am to 10 pm) in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Standby Reservation Fee is calculated as:

  Standby Reservation Rate * standby capacity reserved (kW) * forced outage rate

  The Standby Reservation Rate for Primary Distribution Level service is listed in their filing as 10.07 (Exhibit A, page 4 of 15). Standby capacity reserved is 2,000 kW. FOR is 5%.

  10.07*2,000*.05= $1007.00

- Due to the outage, the customer may be responsible for standby demand charges, depending on whether they exceed the Standby Reservation Fee.
- In order to calculate Standby Demand Charges during a scheduled outage, we first have to calculate the Standby Billing Demand.
- Per the company's filing: "To determine the standby billing demand, the measured demand will be multiplied by the number of days the Scheduled Outage lasts during the month and divided by the number of days in the billing month." (Exhibit A, page 5)
- Here, we have 2,000 kW in standby capacity used for one day of outage divided by 30 days in April. This yields a Standby Billing Demand of 66.67.
- Standby Demand Charges are calculated by multiplying the Standby Billing Demand by the standard rate schedule. The standard rate for General Service served at the Primary Distribution Level is $5.86/kW, minus a $1.75/kW discount for taking primary distribution service. This yields a standard rate of $4.11/kW (see Rate Book, section V, page 10.1)

  Standby Demand Charges: 66.67 * $4.11=$274

  Here, the Standby Reservation Fee is greater, so the customer would pay the reservation fee instead of the demand charges.

Energy Charges

The customer would also be responsible for the energy used during the outage, per their standard rate schedule.

The standard energy charge for a General Service customer in the Minnesota Power Electric Rate Book, section V, page 10.1 is 5.288 cents/kWh.

In a 16 hour outage using 2,000 kW of standby capacity, total kWh would be 32,000.

0.05288*32000 = 1692.16

Total Energy Charges: $1692.16

When the energy charges are added to the Standby Reservation Fee, the total expected standby bill is **$2699.16**.

Scheduled Outage – 8 hours on-peak, 8 hours off-peak

There is no difference between on-peak and off-peak for scheduled outages. The duration of the scheduled outage, in days, is the key. If the outage stretches into two days, you will see an increase, per the calculation of the Standby Billing Demand described above.

Therefore, the total for a 16-hour scheduled outage in which 8 hours were on-peak and 8 hours were off-peak, would still be **$2699.16** (assuming these hours all fell on the same day).

Because there are only so many off-peak hours in the day, a scheduled outage during off-peak hours that lasted over 8 hours would necessarily stretch into a second day and would likely take in some on-peak time.

Scheduled Outage – 32 hours on-peak

Note: Per the company's filing, a customer is permitted to schedule an outage that falls during peak times, as long as the outage is to fall in a shoulder month and proper notice is provided.

For this scheduled outage calculation, we assumed a 32-hour outage that took place during Minnesota Power's peak window (6 am to 10 pm) over two days in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- As above, the Standby Reservation Fee is calculated as:

  Standby Reservation Rate * standby capacity reserved (kW) * forced outage rate

  The Standby Reservation Rate for Primary Distribution Level service is listed in their filing as 10.07 (Exhibit A, page 4 of 15). Standby capacity reserved is 2,000 kW. FOR is 5%.

  10.07*2,000*.05= $1007.00

- Due to the outage, the customer may be responsible for standby demand charges, depending on whether they exceed the Standby Reservation Fee.
- In order to calculate Standby Demand Charges during a scheduled outage, we first have to calculate the Standby Billing Demand.
- Per the company's filing: "To determine the standby billing demand, the measured demand will be multiplied by the number of days the Scheduled Outage lasts during the month and divided by the number of days in the billing month." (Exhibit A, page 5)
- Here, we have 2,000 kW in standby capacity used for two days of outage divided by 30 days in April. This yields a Standby Billing Demand of 133.33.
- Standby Demand Charges are calculated by multiplying the Standby Billing Demand by the standard rate schedule. The standard rate for General Service served at the Primary Distribution Level is $5.86/kW, minus a $1.75/kW discount for taking primary distribution service. This yields a standard rate of $4.11/kW.

  Standby Demand Charges: 133.33 * $4.11=$548

  Here, the Standby Reservation Fee is still greater, so the customer would pay the reservation fee instead of the demand charges.

  <u>Energy Charges</u>

  The customer would also be responsible for the energy used during the outage, per their standard rate schedule.

  The standard energy charge for a General Service customer in the Minnesota Power Electric Rate Book, section V, page 10.1 is 5.288 cents/kWh.

  In a 32 hour outage using 2,000 kW of standby capacity, total kWh would be 64,000.

  0.05288*64000 = 3384.32

  Total Energy Charges: $3384.32

When the energy charges are added to the Standby Reservation Fee, the total expected standby bill is **$4391.32**.

Unscheduled Outage

The company's filed simulation is based on a Large Light & Power customer being served at the Transmission Level, and provides the following for an unscheduled outage calculation:

April Peak Load (on-peak) = 4,000 kW

April Peak Load (off-peak) = 5,000 kW

For our calculations, we assumed a General Service customer being served at the Primary Distribution level. We assumed a 4,000 kW on-peak April peak load, and a 5,000 kW off-peak April peak load. The duration of the outage is assumed to be 16 hours total, with 8 hours falling during peak times and 8 hours falling off-peak.

Therefore, standby capacity used would be:

- 1,000 kW on-peak
- 2,000 kW off-peak

The on-peak and off-peak unscheduled demand charges from the company's filing are:

- 10.68 on-peak demand charge rate (primary distribution)
- 9.50 off-peak demand charge rate (primary distribution)

On-peak demand charges are calculated by multiplying 10.68 by the on-peak standby capacity used, which is 1,000 kW in this example.

Off-peak demand charges are calculated by multiplying 9.50 by the difference between on-peak and off-peak standby capacity used, which is 1,000 kW in this example.

Total Standby Demand Charges = **$20,180.**

<u>Energy Charges</u>

"Energy usage during an Unscheduled Outage, the customer shall pay the Company's hourly incremental energy costs during the time of the sale including third-party transmission costs incurred by the Company plus an energy surcharge of $0.02 per kWh (kilowatt hour). Incremental energy costs are determined after assigning lower cost energy to all firm retail and firm wholesale customers including all inter-system pool sales which involve capacity on a firm or participation basis and to all interruptible sales to Large Power, Large Light and Power, and General Service customers." (p.16)

Xcel Energy

For the following calculations, we built off of Minnesota Power's billing simulations provided in their filing, and adapted each scenario for a General Service customer served at the Primary Distribution level. This analysis has been further revised to reflect clarifications provided in Xcel

Energy's Response to Fresh Energy Information Request #5, Docket No. E-999/CI-15-115, and reflects the following for purposes of reasonable simplification:

a. The energy charges correspond to the General Service tariff rather than the General Time of Day Service tariff that is normally required for customer loads over 1000 kW, and;

b. The Interim Rate Adjustment was not considered.

We assumed a General Service customer with 3,000 kW in nominated standard service, 2,000 kW in reserved standby service, and that the customer was served at the primary distribution level.

Summary

No Outage = $4965.75

Scheduled Outage 16 hours off-peak: $5934.56

Scheduled Outage 16 hours on-peak: $5934.56

Scheduled Outage 8 hours on-peak, 8 hours off-peak: $5934.56

Scheduled Outage 32 hours on-peak: $7958.24

Unscheduled Outage 8 hours on-peak, 8 hours off-peak: $6134.56

No Outage

For the "no outage" calculation, we assumed an April peak load of 3,000 kW.

- For standby charges, only the Standby Reservation Fee would apply. Xcel Energy calculates this as:

  Reservation demand charge * standby capacity reserved (kW)

- The company offers a different demand charge for reserving "scheduled" and "unscheduled" standby service.
- For a customer served at the primary distribution level, the demand charge for reserving scheduled standby service is $2.47/kW of standby capacity reserved.

  Total reservation fee for scheduled: **$4940.00**

- There is also a 25.75/month service charge
- Total Standby Bill = **$4965.75**

Scheduled Outage – 16 hours off-peak

For this scheduled outage calculation, we assumed a 16-hour outage that took place during Xcel Energy's off-peak window over one day in April. Xcel Energy offers customers a grace period of 20 hours per month on standby demand charges (called "Excess Standby Energy Usage" charges), so the number of days of the outage is not important – rather, it is the total number of outage hours that make the difference in the calculations. This grace period is available for both scheduled and unscheduled outages.

The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- Reservation Fee - The company offers a different demand charge for reserving "scheduled" and "unscheduled" standby service.
- For a customer served at the primary distribution level, the demand charge for reserving scheduled standby service is $2.47/kW of standby capacity reserved.

    Total reservation fee for scheduled: **$4940.00**

- Due to the outage, the customer may also be responsible for standby demand charges, whether or not the demand charges exceed the reservation fee – if the outage exceeds the 20 hour/month grace period.
- Xcel's standby demand charges are tied to energy used, and are the result of multiplying the appropriate Excess Standby Energy Charge rate to the total kWh used during an outage (after you take the 20 hour grace allowance off the top).
- In this example, the standby demand charge (a.k.a, Excess Standby Energy Usage charge) rate is $0.04096/kWh.
- The total energy used by 2,000 kW of standby capacity over 16 hours is 32,000 kWh.
- The grace period is calculated as 2,000 kW of standby capacity over 20 hours, which is 40,000 kWh.
- In this example, we are within the 20 hour grace period, so the Excess Standby Energy Usage charges do not apply.

Total reservation fee for scheduled: **$4940.00**

Standby Demand Charges = **$0.**

Energy Charges

The customer would also be responsible for the energy used during the outage, per their standard rate schedule.

The standard energy charge for General Service in the Xcel Energy Electric Rate Book, section 5, sheet 26 is 3.201 cents/kWh. Customers served at the primary distribution level receive a discount of .093 cents/kWh, which results in a standard rate of 3.108 cents/kWh for the purposes of this scenario.

In a 16 hour outage using 2,000 kW of standby capacity, total kWh used would be 32,000.

0.03108*32000 = 994.56

Total Energy Charges: $994.56

There is also a 25.75/month service charge

When the energy charges are added to the Standby Reservation Fee for scheduled service, the total expected standby bill is **$5960.31**

Scheduled Outage – 16 hours on-peak

Note: Per the company's filing, a customer is permitted to schedule an outage that falls during peak times, as long as the outage is to fall in a shoulder month and proper notice is provided.

For this scheduled outage calculation, we assumed a 16-hour outage that took place during Xcel Energy's peak window of 1 pm-7 pm over several days in April. Xcel Energy offers customers a grace period of 20 hours per month on standby demand charges (called "Excess Standby Energy Usage" charges), so the number of days of the outage is not important – rather, it is the total number of outage hours that make the difference in the calculations. This grace period is available for both scheduled and unscheduled outages.

The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- Reservation Fee - The company offers a different demand charge for reserving "scheduled" and "unscheduled" standby service.
- For a customer served at the primary distribution level, the demand charge for reserving scheduled standby service is $2.47/kW of standby capacity reserved.

Total reservation fee for scheduled: **$4940.00**

- Due to the outage, the customer may also be responsible for standby demand charges, whether or not the demand charges exceed the reservation fee – if the outage exceeds the 20 hour/month grace period.
- Xcel's standby demand charges are tied to energy used, and are the result of multiplying the appropriate Excess Standby Energy Charge rate to the total kWh used during an outage (after you take the 20 hour grace allowance off the top).
- In this example, the standby demand charge (a.k.a, Excess Standby Energy Usage charge) rate is $0.04096/kWh.
- The total energy used by 2,000 kW of standby capacity over 16 hours is 32,000 kWh.
- The grace period is calculated as 2,000 kW of standby capacity over 20 hours, which is 40,000 kWh.
- In this example, we are within the 20 hour grace period, so the Excess Standby Energy Usage charges do not apply.

Total reservation fee for scheduled: **$4940.00**

Standby Demand Charges = **$0.**

Energy Charges

The customer would also be responsible for the energy used during the outage, per their standard rate schedule.

The standard energy charge for General Service in the Xcel Energy Electric Rate Book, section 5, sheet 26 is 3.201 cents/kWh. Customers served at the primary distribution level receive a discount of .093 cents/kWh, which results in a standard rate of 3.108 cents/kWh for the purposes of this scenario.

In a 16 hour outage using 2,000 kW of standby capacity, total kWh used would be 32,000.

0.03108*32000 = 994.56

Total Energy Charges: $994.56

There is also a 25.75/month service charge

When the energy charges are added to the Standby Reservation Fee for scheduled service, the total expected standby bill is **$5960.31**

Scheduled Outage – 8 hours on-peak, 8 hours off-peak

There is no difference between on-peak and off-peak for scheduled outages. The duration of the scheduled outage, in hours, is the key. If the outage stretches past the 20 hour/month grace period, Excess Standby Energy Usage charges begin to add up.

Therefore, the total for a 16-hour scheduled outage in which 8 hours were on-peak and 8 hours were off-peak, would still be **$5960.31**

<u>Scheduled Outage – 32 hours on-peak</u>

Note: Per the company's filing, a customer is permitted to schedule an outage that falls during peak times, as long as the outage is to fall in a shoulder month and proper notice is provided.

For this scheduled outage calculation, we assumed a 32-hour outage that took place during Xcel Energy's peak window of 1 pm-7 pm over several days in April.[9] Xcel Energy offers customers a grace period of 20 hours per month on standby demand charges (called "Excess Standby Energy Usage" charges), so the number of days of the outage is not important – rather, it is the total number of outage hours that make the difference in the calculations. This grace period is available for both scheduled and unscheduled outages.

The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- Reservation Fee - The company offers a different demand charge for reserving "scheduled" and "unscheduled" standby service.
- For a customer served at the primary distribution level, the demand charge for reserving scheduled standby service is $2.47/kW of standby capacity reserved.

  Total reservation fee for unscheduled: **$4940.00**

- Due to the outage, the customer may also be responsible for standby demand charges, whether or not the demand charges exceed the reservation fee – if the outage exceeds the 20 hour/month grace period.

[9] Per Xcel's IR Response of 8/29/2016, "Also, under this scenario, the on-peak period is assumed to correspond with the 1:00 p.m. to 7:00 p.m. definition for the proposed Excess Standby Energy Usage Charge, rather than that used for the General Time of Day Service tariff."

- Xcel's standby demand charges are tied to energy used, and are the result of multiplying the appropriate Excess Standby Energy Charge rate to the total kWh used during an outage (after you take the 20 hour grace allowance off the top).
- In this example, the standby demand charge (a.k.a, Excess Standby Energy Usage charge) rate is $0.04096/kWh.
- The total energy used by 2,000 kW of standby capacity over 32 hours is 64,000 kWh.
- The grace period is calculated as 2,000 kW of standby capacity over 20 hours, which is 40,000 kWh.
- After you take the grace period off the top, you are left with 24,000 kWh of Excess Standby Energy Usage.

24,000 * 0.04096 = $983.00

Total reservation fee for scheduled: **$4940.00**

Standby Demand Charges = **$983.00**

Energy Charges

The customer would also be responsible for the energy used during the outage, per their standard rate schedule.

The standard energy charge for General Service in the Xcel Energy Electric Rate Book, section 5, sheet 26 is 3.201 cents/kWh. Customers served at the primary distribution level receive a discount of .093 cents/kWh, which results in a standard rate of 3.108 cents/kWh for the purposes of this scenario.

In a 32 hour outage using 2,000 kW of standby capacity, total kWh used would be 64,000.

0.03108*64000 = 1989.12

Total Energy Charges: $1989.12

There is also a 25.75/month service charge

When the energy charges are added to the Standby Reservation Fee for scheduled service, the total expected standby bill is **$7937.87**

Unscheduled Outage

Xcel Energy differentiates between scheduled and unscheduled only in the Standby Reservation Fee. All other calculations would be the same between a scheduled and unscheduled outage.

For this unscheduled outage calculation, we assumed a 16-hour outage that took place during Xcel Energy's peak window of 1 pm-7 pm over several days in April. Xcel Energy offers customers a grace period of 20 hours per month on standby demand charges (called "Excess Standby Energy Usage" charges), so the number of days of the outage is not important – rather, it is the total number of outage hours that make the difference in the calculations. This grace period is available for both scheduled and unscheduled outages.

The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- Reservation Fee - The company offers a different demand charge for reserving "scheduled" and "unscheduled" standby service.

  For a customer served at the primary distribution level, the demand charge for reserving unscheduled standby service is $2.57/kW of standby capacity reserved.

  Total reservation fee for unscheduled: **$5140.00**

- Due to the outage, the customer may also be responsible for additional standby demand charges (a.k.a, Excess Standby Energy Usage charges), whether or not the standby demand charges exceed the reservation fee – if the outage exceeds the 20 hour/month grace period.
- Xcel's standby demand charges (a.k.a, Excess Standby Energy Usage charges) are tied to energy used, and are the result of multiplying the appropriate Excess Standby Energy Usage rate to the total kWh used during an outage (after you take the 20 hour grace allowance off the top).
- In this example, the standby demand charge (a.k.a, Excess Standby Energy Usage charge) rate is $0.04096/kWh because our sample outage takes place in April, a shoulder month.
- The total energy used by 2,000 kW of standby capacity over 16 hours is 32,000 kWh.
- The grace period is calculated as 2,000 kW of standby capacity over 20 hours, which is 40,000 kWh.
- In this example, we are within the 20 hour grace period, so the additional standby demand charges (a.k.a, Excess Standby Energy Usage charges) do not apply.

Total reservation fee for unscheduled: **$5140.00**

Standby Demand Charges = **$0.**

Energy Charges

The customer would also be responsible for the energy used during the outage, per their standard rate schedule.

The standard energy charge for General Service in the Xcel Energy Electric Rate Book, section 5, sheet 26 is 3.201 cents/kWh. Customers served at the primary distribution level receive a discount of .093 cents/kWh, which results in a standard rate of 3.108 cents/kWh for the purposes of this scenario.

In a 16 hour outage using 2,000 kW of standby capacity, total kWh used would be 32,000.

0.03108*32000 = 994.56

Total Energy Charges: $994.56

There is also a 25.75/month service charge

When the energy charges are added to the Standby Reservation Fee for unscheduled service, the total expected standby bill is **$6160.31**.

Otter Tail Power

For the following calculations, we built off of Minnesota Power's billing simulations provided in their filing, and adapted each scenario for a General Service customer served at the Primary Distribution level. This analysis has been further revised to reflect clarifications provided in Otter Tail Power's Response to Fresh Energy Information Request #4, Docket No. E-999/CI-15-115.

We assumed a General Service customer with 3,000 kW in nominated standard service, 2,000 kW in reserved standby service, and that the customer was served at the primary distribution level.

Summary

No Outage = $1632.39

Scheduled Outage 16 hours off-peak: $3166.79

Scheduled Outage 16 hours on-peak: $4113.03

Scheduled Outage 8 hours on-peak, 8 hours off-peak: $3639.91

Scheduled Outage 32 hours on-peak: $6593.67

Unscheduled Outage 4 hours on-peak, 4 hours shoulder, 8 hours off-peak: $4407.67

No Outage

For the "no outage" calculation, we assumed an April peak load of 3,000 kW. April is considered a "Winter" month.

- Otter Tail differentiates between firm and non-firm standby service. Here we assume firm standby service.
- For standby charges, only the Standby Reservation Fee and Facilities Charge would apply. Otter Tail Power calculates this as:

  Winter Reservation Charge * standby capacity reserved (kW)

- For a customer served at the primary distribution level, according to Otter Tail's proposed standby rate changes in its pending rate case, the winter reservation charge is $0.21403/kW of standby capacity reserved.

  0.21403* 2000 = **$428.06**

- There is another fixed charge for Primary and Secondary customers, called the "Standby Facilities Charge" which is a fixed amount charged per month per kW of contracted standby demand.
- The Standby Facilities Charge for a customer on primary distribution service is 45.00 cents/kW.

  0.45 * 2000 = **$900.00**

Standby Reservation Fee = $428.06

Standby Facilities Charge = $900.00

There is also a customer charge of $304.33.

Total = $1632.39

Scheduled Outage – 16 hours off-peak

For this scheduled outage calculation, we assumed a 16-hour outage that took place during Otter Tail's off-peak window over four days in April. Note that Otter Tail offers customers a waiver for the daily on-peak backup charge for scheduled maintenance during the shoulder months (April, May, October, and November), as long as the outage is shorter than 30 continuous days.

The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- Reservation Fee - Otter Tail Power calculates this as:

  Winter Reservation Charge * standby capacity reserved (kW)

- For a customer served at the primary distribution level, the winter reservation charge is $0.21403/kW of standby capacity reserved.

  0.21403* 2000 = **$428.06**

- There is another fixed charge for Primary and Secondary customers, called the "Standby Facilities Charge" which is a fixed amount charged per month per kW of contracted standby demand.
- The Standby Facilities Charge for a customer on primary distribution service is 45.00 cents/kW.

  0.45 * 2000 = **$900.00**

- For standby demand charges, there is daily on-peak backup charge (Winter) that is charged per kW of standby capacity used.
- The daily on-peak backup charge (Winter) for customers served at the primary distribution level is 0.408/kW. For a one day outage, this calculates as:

  0.408 * 2000 = **$816.00**

- However, Otter Tail offers customers a **waiver** for the daily on-peak backup charge for scheduled maintenance during the shoulder months (April, May, October, and November) as long as the outage is shorter than 30 continuous days.
- Therefore, there would be no daily on-peak backup charge under this scenario.

Standby Reservation Fee = $428.06
Standby Facilities Charge = $900.00

Standby Demand Charges = $0

Energy Charges

The customer would also be responsible for the energy used during the outage. Energy charges differ in the summer and winter months, and depending on whether energy use occurs on-peak or off-peak.

The Winter off-peak energy charge for primary distribution level customers is 4.795 cents/kWh.

In a 16 hour outage using 2,000 kW of standby capacity, total kWh used would be 32,000.

0.04795*32000 = $1534.40

Total Energy Charges: $1534.40

Standby Reservation Fee = $428.06

Standby Facilities Charge = $900.00

Energy Charges = $1534.40

There is also a customer charge of 304.33

When the energy charges are added to the Standby Reservation Fee, the Standby Facilities Charge, and the expected standby demand charges (which are zero), the total expected standby bill is **$3166.79**

Scheduled Outage – 16 hours on-peak

Note: Per the company's filing, a customer is permitted to schedule an outage that falls during peak times, as long as the outage is to fall in a shoulder month and proper notice is provided.

For this scheduled outage calculation, we assumed a 16-hour outage that took place during Otter Tail's peak window over four days in April. Note that Otter Tail offers customers a waiver for the daily on-peak backup charge for scheduled maintenance during the shoulder months (April, May, October, and November), as long as the outage is shorter than 30 continuous days.

The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- Reservation Fee - Otter Tail Power calculates this as:

  Winter Reservation Charge * standby capacity reserved (kW)

- For a customer served at the primary distribution level, the winter reservation charge is $0.21403/kW of standby capacity reserved.

  0.21403* 2000 = **$428.06**

- There is another fixed charge for Primary and Secondary customers, called the “Standby Facilities Charge” which is a fixed amount charged per month per kW of contracted standby demand.
- The Standby Facilities Charge for a customer on primary distribution service is 45.00 cents/kW.

  0.45 * 2000 = **$900.00**

- For standby demand charges, there is daily on-peak backup charge (Winter) that is charged per kW of standby capacity used.
- The daily on-peak backup charge (Winter) for customers served at the primary distribution level is 0.408/kW. For a one day outage, this calculates as:

  0.408 * 2000 = **$816.00**

- However, Otter Tail offers customers a **<u>waiver</u>** for the daily on-peak backup charge for scheduled maintenance during the shoulder months (April, May, October, and November) as long as the outage is shorter than 30 continuous days.
- Therefore, there would be no daily on-peak backup charge under this scenario.

  Standby Reservation Fee = $428.06
  Standby Facilities Charge = $900.00
  Standby Demand Charges = $0

Energy Charges

The customer would also be responsible for the energy used during the outage. Energy charges differ in the summer and winter months, and depending on whether energy use occurs on-peak or off-peak.

The Winter on-peak energy charge for primary distribution level customers is 7.752 cents/kWh.

In a 16 hour outage using 2,000 kW of standby capacity, total kWh used would be 32,000.

0.07752*32000 = $2480.64 (on-peak)

Total Energy Charges: $2480.64

Standby Reservation Fee = $428.06

Standby Facilities Charge = $900.00

Energy Charges = $2480.64

There is also a customer charge of 304.33

When the energy charges are added to the Standby Reservation Fee, the Standby Facilities Charge, and the expected standby demand charges (which are zero), the total expected standby bill is **$4113.03**

Scheduled Outage – 8 hours on-peak, 8 hours off-peak

The Reservation Fee would be the same as above: $428.06.

Because this is still a scheduled outage in a shoulder month, it would also qualify for the waiver of the daily backup charge/standby charges.

Therefore, the only difference would be in the energy charges, which would reflect on-peak and off-peak.

The Winter on-peak energy charge for primary distribution level customers is 7.752 cents/kWh. The Winter off-peak energy charge for primary distribution level customers is 4.795 cents/kWh.

In a 16 hour outage using 2,000 kW of standby capacity, total kWh used would be 32,000. Half of these are peak, half are off-peak.

0.07752*16000 = $1240.32 (on-peak)

0.04795*16000 = $767.20 (off-peak)

Total Energy Charges: $2007.52

Standby Reservation Fee = $428.06

Standby Facilities Charge = $900.00

Energy Charges = $2007.52

There is also a customer charge of 304.33

When the energy charges are added to the Standby Reservation Fee, the Standby Facilities Charge and the expected standby demand charges (which are zero), the total expected standby bill is **$3639.91**

Scheduled Outage – 32 hours on-peak

Note: Per the company's filing, a customer is permitted to schedule an outage that falls during peak times, as long as the outage is to fall in a shoulder month and proper notice is provided.

For this scheduled outage calculation, we assumed a 32-hour outage that took place during Otter Tail's peak window over several days in April. Note that Otter Tail offers customers a waiver for the daily on-peak backup charge for scheduled maintenance during the shoulder months (April, May, October, and November), as long as the outage is shorter than 30 continuous days.

The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard nominated service and 2,000 kW in reserved standby capacity.

- Reservation Fee - Otter Tail Power calculates this as:

  Winter Reservation Charge * standby capacity reserved (kW)

- For a customer served at the primary distribution level, the winter reservation charge is $0.21403/kW of standby capacity reserved.

  0.21403* 2000 = **$428.06**

- There is another fixed charge for Primary and Secondary customers, called the "Standby Facilities Charge" which is a fixed amount charged per month per kW of contracted standby demand.
- The Standby Facilities Charge for a customer on primary distribution service is 45.00 cents/kW.

0.45 * 2000 = **$900.00**

- For standby demand charges, there is daily on-peak backup charge (Winter) that is charged per kW of standby capacity used.
- The daily on-peak backup charge (Winter) for customers served at the primary distribution level is 0.408/kW. For a one day outage, this calculates as:

0.408 * 2000 = **$816.00**

- However, Otter Tail offers customers a **waiver** for the daily on-peak backup charge for scheduled maintenance during the shoulder months (April, May, October, and November) as long as the outage is shorter than 30 continuous days.
- Therefore, there would be no daily on-peak backup charge under this scenario.

Standby Reservation Fee = $428.06
Standby Facilities Charge = $900.00
Standby Demand Charges = $0

Energy Charges

The customer would also be responsible for the energy used during the outage. Energy charges differ in the summer and winter months, and depending on whether energy use occurs on-peak or off-peak.

The Winter on-peak energy charge for primary distribution level customers is 7.752 cents/kWh.

In a 16 hour outage using 2,000 kW of standby capacity, total kWh used would be 32,000.

0.07752*64000 = $4961.28 (on-peak)

Total Energy Charges: $4961.28

There is also a customer charge of 304.33

When the energy charges are added to the Standby Reservation Fee, the Standby Facilities Charge, and the expected standby demand charges (which are zero), the total expected standby bill is **$6593.67**

Unscheduled Outage

For this calculation, we assumed a one-day unscheduled outage that took place in April. The duration of the outage is assumed to be 16 hours total, with 4 hours falling during peak times, 4 hours falling during shoulder times, and 8 hours falling off-peak. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard service and 2,000 kW in reserved standby capacity.

For an unscheduled outage, the major difference is that the additional daily backup demand charge will apply.

- Reservation Fee - Otter Tail Power calculates this as:

    Winter Reservation Charge * standby capacity reserved (kW)

- For a customer served at the primary distribution level, the winter reservation charge is $0.21403/kW of standby capacity reserved.

    0.21403* 2000 = **$428.06**

- There is another fixed charge for Primary and Secondary customers, called the "Standby Facilities Charge" which is a fixed amount charged per month per kW of contracted standby demand.
- The Standby Facilities Charge for a customer on primary distribution service is 45.00 cents/kW.

    0.45 * 2000 = **$900.00**

- The daily on-peak backup charge (Winter) for customers served at the primary distribution level is 0.408/kW. For a one day outage, this calculates as:

    0.408 * 2000 = **$816.00**

Standby Reservation Fee = $428.06
Standby Facilities Charge = $900.00
Standby Demand Charges (a.k.a. Daily On-Peak Backup Service Charges) = $816.00

Energy Charges

The customer would also be responsible for the energy used during the outage. Energy charges differ in the summer and winter months, and depending on whether energy use occurs on-peak or off-peak.

The Winter on-peak energy charge for primary distribution level customers is 7.752 cents/kWh. The Winter off-peak energy charge for primary distribution level customers is 4.795 cents/kWh. The Winter shoulder energy charge for primary distribution level customers is 7.149 cents/kWh.

In a 16 hour outage using 2,000 kW of standby capacity, total kWh used would be 32,000. 8,000 of these are peak, 8,000 of these are shoulder, and 16,000 of these are off-peak.

0.07752*8000= $620.16 (on-peak)

0.04795*16000 = $767.20 (off-peak)

0.07149*8000 = $571.92 (shoulder)

Total Energy Charges: $1959.28

Standby Reservation Fee = $428.06
Standby Facilities Charge = $900.00
Standby Demand Charges (a.k.a. Daily On-Peak Backup Service Charges) = $816.00
Energy Charges = $1959.28

There is also a customer charge of 304.33

When the energy charges are added to the Standby Reservation Fee, the Standby Facilities Charge and the expected standby demand charges, the total expected standby bill is **$4407.67**

Dakota Electric

For the following calculations, we adapted Minnesota Power's billing simulations per Dakota Electric's response to Fresh Energy's Information Request dated August 5, 2016. This analysis has been further revised to reflect clarifications provided in Dakota Electric Association Response to Fresh Energy Information Request #7, Docket No. E-999/CI-15-115.

The following key adaptations have been made:

- Clarification that the standby service is fully backing up the capacity of the on-site generation – which is designed and anticipated to operate 100% of the time.
- Firm utility service would be provided under Schedule 46 which does not have on-peak and off-peak demand.
- We have assumed distribution primary level service.

The customer is signed up for 3,000 kW in standard service and has reserved 2,000 kW in standby capacity.

Summary

No Outage = $6594

Scheduled Outage 16 hours off-peak: $20,127.14

Scheduled Outage 16 hours on-peak: $20,127.14

Scheduled Outage 8 hours on-peak, 8 hours off-peak: $20,127.14

Scheduled Outage 32 hours on-peak: $22,560.67

Unscheduled Outage 8 hours on-peak, 8 hours off-peak: $20,127.14

No Outage

For the "no outage" calculation, we assumed an April peak load of 3,000 kW.

- For standby charges, only the Standby Reservation Fee would apply. Dakota Electric calculates this as:

    Standby Reservation Rate * standby capacity reserved (kW)

    The Standby Reservation Rate for distribution level (primary) is listed in their filing as 3.28 (section V, sheet 31.1). Standby capacity reserved is 2,000 kW.

    3.28 * 2,000 = $6560.00

Total "No Outage" Standby Bill = **$6560.00**

Plus $34 Customer Charge = **$6594.00**

Note: There would be direct pass-through of wholesale charges for generation and transmission as an additional part of the standby reservation fee.

Scheduled Outage – 16 hours off-peak

Note: There is no difference between scheduled and unscheduled for Dakota Electric's standby billing. There is also no difference between on-peak and off-peak in Dakota Electric's standby billing (other than any differences reflected in the direct pass-through of wholesale charges).

The total kW of reserved standby capacity is the key factor, as that – and the high standby demand charge rate – drive the costs under all outage scenarios.

For this scheduled outage calculation, we assumed a 16-hour outage that took place during Dakota Electric's off-peak window in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard service and 2,000 kW in reserved standby capacity.

- Per DEA IR Response 8/23/2016, if standby demand occurs in a given month, then the equivalent amount of demand is subtracted from the billing units applied to the standby reservation fee. For this outage scenario, the generator is not operating and the usage provided by the utility is 2,000 kW, which is the same amount as the reserved standby amount, resulting in a standby reservation fee of zero. (See also "Billing Demand" clause of proposed revision to Standby Rider.)
- Due to the outage, the customer is responsible for standby demand charges.
- The non-Summer demand charge is $9.16 (see Exhibit B), minus a $0.15 per kW primary service demand discount (see DEA IR Response 8/23/2016; see also DEA Rate Book Schedule 46, section V, sheet 16, revision 3). The net demand charge is $9.01 per kW of standby capacity used.
- In order to calculate Standby Demand Charges, we multiply the net non-Summer demand charge of 9.01 by the total kW of standby capacity used:

  Standby Demand Charges: 9.01 * 2000 = **$18,020**

  Standby Reservation Fee = **$0**

Energy Charges

From DEA IR Response 8/23/2016 (see also DEA Rate Book Schedule 46, section V, sheet 16, revision 3):

> *The Schedule 46 energy charges are based on load factor. That is, the energy billed in each block is determined in relationship to the monthly demand. The blocks are measured as 200 kWh per kW.*
>
> *For example, if a consumer has a monthly demand of 100 kW, then the first 20,000 kWh (200 kWh x 100 kW) are billed in the first block. The next 20,000 kWh (200 kWh x 100 kW) are billed in the second block. All monthly kWh over 40,000 kWh (400 kWh x 100 kW) is billed in the third block. For the scenarios provided all energy falls in the first block since the monthly kWh is less than 400,000 (200 kWh x 2,000 kW).*

The rate for the first block is:

0.0776 per kW for the first 200 kWh * 2,000kW

In a 16 hour outage, using 2,000 kW of standby capacity, 32,000 kWh would be used.

Therefore, in this scenario, the energy charge calculation would be:

(0.0776*32000) = **$2483.20**

Finally, as noted in DEA IR Response 8/23/2016, there is a 2% discount applied to the consumption for Schedule 46 primary service (discount does not apply to the standby reservation fee). (See also DEA Rate Book Schedule 46, section V, sheet 16, revision 3.)

Reservation Fee = 0

Demand Charges = 18,020

Energy Charges = 2483.20

Total of Demand plus Energy = 20,503.20

2% Discount Applied = 20,093.14

When the energy charges are added to the Standby Reservation Fee and Standby Demand Charges, and the discount is applied, the total expected standby bill is **$20,093.14.**

Plus $34 Customer Charge = **$20,127.14**

Scheduled Outage – 16 hours on-peak

Note: There is no difference between scheduled and unscheduled for Dakota Electric's standby billing. There is also no difference between on-peak and off-peak in Dakota Electric's standby billing (other than any differences reflected in the direct pass-through of wholesale charges).

For this scheduled outage calculation, we assumed a 16-hour outage that took place during Dakota Electric's peak window over several days in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard service and 2,000 kW in reserved standby capacity.

- Per DEA IR Response 8/23/2016, if standby demand occurs in a given month, then the equivalent amount of demand is subtracted from the billing units applied to the standby reservation fee. For this outage scenario, the generator is not operating and the usage provided by the utility is 2,000 kW, which is the same amount as the reserved standby amount, resulting in a standby reservation fee of zero. (See also "Billing Demand" clause of proposed revision to Standby Rider.)

- Due to the outage, the customer is responsible for standby demand charges.
- The non-Summer demand charge is $9.16 (see Exhibit B), minus a $0.15 per kW primary service demand discount (see DEA IR Response 8/23/2016; see also DEA Rate Book Schedule 46, section V, sheet 16, revision 3). The net demand charge is $9.01 per kW of standby capacity used.
- In order to calculate Standby Demand Charges, we multiply the net non-Summer demand charge of 9.01 by the total kW of standby capacity used:

  Standby Demand Charges: 9.01 * 2000 = **$18,020**

  Standby Reservation Fee = **$0**

Energy Charges

From DEA IR Response 8/23/2016 (see also DEA Rate Book Schedule 46, section V, sheet 16, revision 3):

> *The Schedule 46 energy charges are based on load factor. That is, the energy billed in each block is determined in relationship to the monthly demand. The blocks are measured as 200 kWh per kW.*
>
> *For example, if a consumer has a monthly demand of 100 kW, then the first 20,000 kWh (200 kWh x 100 kW) are billed in the first block. The next 20,000 kWh (200 kWh x 100 kW) are billed in the second block. All monthly kWh over 40,000 kWh (400 kWh x 100 kW) is billed in the third block. For the scenarios provided all energy falls in the first block since the monthly kWh is less than 400,000 (200 kWh x 2,000 kW).*

The rate for the first block is:

0.0776 per kW for the first 200 kWh * 2,000kW

In a 16 hour outage, using 2,000 kW of standby capacity, 32,000 kWh would be used.

Therefore, in this scenario, the energy charge calculation would be:

(0.0776*32000) = **$2483.20**

Finally, as noted in DEA IR Response 8/23/2016, there is a 2% discount applied to the consumption for Schedule 46 primary service (discount does not apply to the standby reservation fee). (See also DEA Rate Book Schedule 46, section V, sheet 16, revision 3.)

Reservation Fee = 0

Demand Charges = 18,020

Energy Charges = 2483.20

Total of Demand plus Energy = 20,503.20

2% Discount Applied = 20,093.14

When the energy charges are added to the Standby Reservation Fee and Standby Demand Charges, and the discount is applied, the total expected standby bill is **$20,093.14.**

Plus $34 Customer Charge = **$20,127.14**

Scheduled Outage – 8 hours on-peak, 8 hours off-peak

Note: There is no difference between scheduled and unscheduled for Dakota Electric's standby billing. There is also no difference between on-peak and off-peak in Dakota Electric's standby billing (other than any differences reflected in the direct pass-through of wholesale charges).

The total kW of reserved standby capacity is the key factor, as that – and the high standby demand charge rate – drive the costs under all outage scenarios.

Therefore, the total for a 16-hour scheduled outage in which 8 hours were on-peak and 8 hours were off-peak, would still be **$20,093.14**.

Plus $34 Customer Charge = $**20,127.14**

Because there are only so many off-peak hours in the day, a scheduled outage during off-peak hours that lasted over 8 hours would necessarily stretch into a second day and would likely take in some on-peak time.

Scheduled Outage – 32 hours on-peak

Note: There is no difference between scheduled and unscheduled for Dakota Electric's standby billing. There is also no difference between on-peak and off-peak in Dakota Electric's standby billing (other than any differences reflected in the direct pass-through of wholesale charges).

For this scheduled outage calculation, we assumed a 32-hour outage that took place during Dakota Electric's peak window over several days in April. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard service and 2,000 kW in reserved standby capacity.

- Per DEA IR Response 8/23/2016, if standby demand occurs in a given month, then the equivalent amount of demand is subtracted from the billing units applied to the standby reservation fee. For this outage scenario, the generator is not operating and the usage provided by the utility is 2,000 kW, which is the same amount as the reserved standby amount, resulting in a standby reservation fee of zero.

- Due to the outage, the customer is responsible for standby demand charges.
- The non-Summer demand charge is $9.16 (see Exhibit B), minus a $0.15 per kW primary service demand discount (See DEA IR Response 8/23/2016). The net demand charge is $9.01 per kW of standby capacity used.
- In order to calculate Standby Demand Charges, we multiply the net non-Summer demand charge of 9.01 by the total kW of standby capacity used:

Standby Demand Charges: 9.01 * 2000 = **$18,020**

Standby Reservation Fee = **$0**

Energy Charges

From DEA IR Response 8/23/2016 (see also DEA Rate Book Schedule 46, section V, sheet 16, revision 3):

> *The Schedule 46 energy charges are based on load factor. That is, the energy billed in each block is determined in relationship to the monthly demand. The blocks are measured as 200 kWh per kW.*
>
> *For example, if a consumer has a monthly demand of 100 kW, then the first 20,000 kWh (200 kWh x 100 kW) are billed in the first block. The next 20,000 kWh (200 kWh x 100 kW) are billed in the second block. All monthly kWh over 40,000 kWh (400 kWh x 100 kW) is billed in the third block. For the scenarios provided all energy falls in the first block since the monthly kWh is less than 400,000 (200 kWh x 2,000 kW).*

The rate for the first block is:

0.0776 per kW for the first 200 kWh * 2,000kW

In a 32 hour outage, using 2,000 kW of standby capacity, 64,000 kWh would be used. Therefore, in this scenario, the energy charge calculation would be:

(0.0776*64000) = **$4966.40**

Finally, as noted in DEA IR Response 8/23/2016, there is a 2% discount applied to the consumption for Schedule 46 primary service (discount does not apply to the standby reservation fee).

Reservation Fee = 0

Demand Charges = 18,020

Energy Charges = 4966.40

Total of Demand plus Energy = 22,986.40

2% Discount Applied = 22,526.67

When the energy charges are added to the Standby Reservation Fee and Standby Demand Charges, and the discount is applied, the total expected standby bill is **$22,526.67.**

Plus $34 Customer Charge = **$22,560.67**

Unscheduled Outage

Note: There is no difference between scheduled and unscheduled for Dakota Electric's standby billing. There is also no difference between on-peak and off-peak in Dakota Electric's standby billing (other than any differences reflected in the direct pass-through of wholesale charges).

For this calculation, we assumed an unscheduled outage that took place over several days in April. The duration of the outage is assumed to be 16 hours total, with 8 hours falling during peak times and 8 hours falling off-peak. The assumed peak load was 5,000 kW. We are still assuming 3,000 kW in standard service and 2,000 kW in reserved standby capacity.

- Per DEA IR Response 8/23/2016, if standby demand occurs in a given month, then the equivalent amount of demand is subtracted from the billing units applied to the standby reservation fee. For this outage scenario, the generator is not operating and the usage provided by the utility is 2,000 kW, which is the same amount as the reserved standby amount, resulting in a standby reservation fee of zero.
- Due to the outage, the customer is responsible for standby demand charges.
- The non-Summer demand charge is $9.16 (see Exhibit B), minus a $0.15 per kW primary service demand discount (See DEA IR Response 8/23/2016). The net demand charge is $9.01 per kW of standby capacity used.
- In order to calculate Standby Demand Charges, we multiply the net non-Summer demand charge of 9.01 by the total kW of standby capacity used:

  Standby Demand Charges: 9.01 * 2000 = **$18,020**

Standby Reservation Fee = **$0**

Energy Charges

From DEA IR Response 8/23/2016 (see also DEA Rate Book Schedule 46, section V, sheet 16, revision 3):

> *The Schedule 46 energy charges are based on load factor. That is, the energy billed in each block is determined in relationship to the monthly demand. The blocks are measured as 200 kWh per kW.*
>
> *For example, if a consumer has a monthly demand of 100 kW, then the first 20,000 kWh (200 kWh x 100 kW) are billed in the first block. The next 20,000 kWh (200 kWh x 100 kW) are billed in the second block. All monthly kWh over 40,000 kWh (400 kWh x 100 kW) is billed in the third block. For the scenarios provided all energy falls in the first block since the monthly kWh is less than 400,000 (200 kWh x 2,000 kW).*

The rate for the first block is:

0.0776 per kW for the first 200 kWh * 2,000kW

In a 16 hour outage, using 2,000 kW of standby capacity, 32,000 kWh would be used. Therefore, in this scenario, the energy charge calculation would be:
(0.0776*32000) = **$2483.20**

Finally, as noted in DEA IR Response 8/23/2016, there is a 2% discount applied to the consumption for Schedule 46 primary service (discount does not apply to the standby reservation fee).

Reservation Fee = 0

Demand Charges = 18,020

Energy Charges = 2483.20

Total of Demand plus Energy = 20,503.20

2% Discount Applied = 20,093.14

When the energy charges are added to the Standby Reservation Fee and Standby Demand Charges, and the discount is applied, the total expected standby bill is **$20,093.14.**

Plus $34 Customer Charge = **$20,127.14**

Table 1 - Overview of Total Standby Bills[1]

	DTE – Rider 3 current	DTE – Rider 3 proposed	DTE – Rider 3 proposed (70%)	Consumers – GSG-2	UPPCO	UMERC	Minnesota Power	Xcel Energy	Otter Tail Power	Dakota Electric[2]
No Outage	10,535	11,955	8,451	8300	0	0	1007	4966	1632	6594
Scheduled 16-hour off-peak	11,657	13,021	9,190	9246	2911	2218	2699	5961	3167	20,127
Scheduled 16-hour on-peak	18,653	20,881	14,699	11,645	3883	3098	2699	5961	4113	20,127
Scheduled 8-hour on peak, 8-hour off-peak	13,405	15,041	10,611	11,191	3397	2658	2699	5961	3640	20,127
Scheduled 32-hour on-peak	30,272	33,626	23,621	14,833	7766	6196	4391	7958	6594	22,561
Unscheduled 8-hour on-peak, 8-hour off-peak	17,545	19,401	13,663	11,191	31,631	30,536	20,180 plus hourly energy	6161	4408	20,127

[1] Based on 2,000 kW in standby contract capacity, with customer served at primary voltage level. Consumers Energy outages are assumed to have taken place in March; all other outages are assumed to have taken place in April.
[2] Dakota Electric totals incorporate 2% discount for primary distribution service.

Table 2 - No outage

	DTE – Rider 3 current	DTE – Rider 3 proposed	DTE – Rider 3 proposed (70%)	Consumers – GSG-2	UPPCO	UMERC	Minnesota Power	Xcel Energy	Otter Tail Power	Dakota Electric
Service Charge	275	275	275	200	0	0	0	26	304	34
Delivery Capacity/Distribution Charge	6760	7860	5502	8100	0	0	0	0	900	0
Reservation Fee	3500	3820	2674	0	0	0	1007	4940	428	6560
PS Capacity/Demand Charges	0	0	0	0	0	0	0	0	0	0
Energy Charges	0	0	0	0	0	0	0	0	0	0
…										
Subtotal of Monthly Delivery and Customer Charges	7035	8135	5777	8300	0	0	1007	4966	1204	34
Subtotal of Monthly Reservation and Daily Demand	3500	3820	2674	0	0	0	0	0	428	6560
Subtotal of Energy Charges	0	0	0	0	0	0	0	0	0	0
TOTAL	10,535	11,955	8451	8300	0	0	1007	4966	1632	6594

Table 3 - Scheduled Outage 16 hours off-peak

	DTE – Rider 3 current	DTE – Rider 3 proposed	DTE – Rider 3 proposed (70%)	Consumers – GSG-2	UPPCO	UMERC	Minnesota Power	Xcel Energy	Otter Tail Power	Dakota Electric
Service Charge	275	275	275	200	0	0	0	26	304	34
Delivery Capacity/Distribution Charge	6760	7860	5502	8100	0	0	0	0	900	0
Reservation Fee	3500	3820	2674	0	0	0	1007	4940	428	0
PS Capacity/Demand Charges	0	0	0	0	1106	1182	0	0	0	18,020
Energy Charges[3]	1122.24	1065	739	946	1805	1036	1692	995	1534	2483
…										
Subtotal of Monthly Delivery and Customer Charges	7035	8135	5777	8300	0	0	0	26	1204	34
Subtotal of Monthly Reservation and Daily Demand	3500	3820	2674	0	1106	1182	1007	4940	428	18,020

[3] Energy charges calculations for Consumers Energy provided by Consumers Energy.

Subtotal of Energy Charges	1122.24	1065	739	946	1805	1036	1692	995	1534	2483
TOTAL	11,657.24	13,020	9190	9246	2911	2218	2699	5961	3167	20,127[4]

Table 4 - Scheduled Outage 16 hours on-peak

	DTE – Rider 3 current	DTE – Rider 3 proposed	DTE – Rider 3 proposed (70%)	Consumers – GSG-2	UPPCO	UMERC	Minnesota Power	Xcel Energy	Otter Tail Power	Dakota Electric
Service Charge	275	275	275	200	0	0	0	26	304	34
Delivery Capacity/Distribution Charge	6760	7860	5502	8100	0	0	0	0	900	0
Reservation Fee	0	0	0	0	0	0	1007	4940	428	0
PS Capacity/Demand Charges	10,400	11360	7952	2232	1106	1182	0	0	0	18,020
Energy Charges	1218	1385	970	1113	2777	1916	1692	995	2481	2483
…										
Subtotal of Monthly Delivery and Customer Charges	7035	8135	5777	8300	0	0	0	26	1204	34
Subtotal of Monthly Reservation and Daily Demand	0	11,360	7952	2232	1106	1182	1007	4940	428	18,020

4 Dakota Electric totals incorporate 2% discount for primary distribution service.

Subtotal of Energy Charges	1218	1385	970	1113	2777	1916	1692	995	2481	2483
TOTAL	18,653	20,880	14,699	11,645	3883	3098	2699	5961	4113	20,127[5]

Table 5 - Scheduled Outage 8 hours on-peak, 8 hours off-peak

	DTE – Rider 3 current	DTE – Rider 3 proposed	DTE – Rider 3 proposed (70%)	Consumers – GSG-2	UPPCO	UMERC	Minnesota Power	Xcel Energy	Otter Tail Power	Dakota Electric
Service Charge	275	275	275	200	0	0	0	0	304	34
Delivery Capacity/Distribution Charge	6760	7860	5502	8100	0	0	0	0	900	0
Reservation Fee	0	0	0	0	0	0	1007	4940	428	0
PS Capacity/Demand Charges	5200	5680	3976	1116	1106	1182	0	0	0	18,020
Energy Charges	1170	1226	858	1775	2291	1476	1692	995	2008	2483
…										
Subtotal of Monthly Delivery and Customer Charges	7035	8135	5777	8300	0	0	0	26	1204	34

[5] Dakota Electric totals incorporate 2% discount for primary distribution service.

Subtotal of Monthly Reservation and Daily Demand	5200	5680	3976	1116	1106	1182	1007	4940	428	18,020
Subtotal of Energy Charges	1170	1226	858	1775	2291	1476	1692	995	2008	2483
TOTAL	13,405	15,041	10,611	11,191	3397	2658	2699	5961	3640	20,127[6]

Table 6 - Scheduled Outage 32 hours on-peak

	DTE – Rider 3 current	DTE – Rider 3 proposed	DTE – Rider 3 proposed (70%)	Consumers – GSG-2	UPPCO	UMERC	Minnesota Power	Xcel Energy	Otter Tail Power	Dakota Electric
Service Charge	275	275	275	200	0	0	0	26	304	34
Delivery Capacity/Distribution Charge	6760	7860	5502	8100	0	0	0	0	900	0
Reservation Fee	0	0	0	0	0	0	1007	4940	428	0
PS Capacity/Demand Charges	20,800	22720	15904	4463	2212	2364	0	983	0	18,020
Energy Charges	2436	2771	1940	2070	5554	3832	3384	1989	4961	4966
…										

[6] Dakota Electric totals incorporate 2% discount for primary distribution service.

Subtotal of Monthly Delivery and Customer Charges	7035	8135	5777	8300	0	0	0	26	1204	34
Subtotal of Monthly Reservation and Daily Demand	20,800	22720	15904	4463	2212	2364	1007	5923	428	18,020
Subtotal of Energy Charges	2436	2771	1940	2070	5554	3832	3384	1989	4961	4966
TOTAL	30,272	33,626	23,621	14,833	7766	6196	4391	7938	6594	22,561[7]

Table 7 - Unscheduled Outage 8 hours on-peak, 8 hours off-peak

	DTE – Rider 3 current	DTE – Rider 3 proposed	DTE – Rider 3 proposed (70%)	Consumers – GSG-2	UPPCO	UMERC	Minnesota Power	Xcel Energy	Otter Tail Power	Dakota Electric
Service Charge	275	275	275	200	0	0	0	26	304	34
Delivery Capacity/Distribution Charge	6760	7860	5502	8100	0	0	0	0	900	0
Reservation Fee	0	0	0	0	0	0	0	5140	428	0
PS Capacity/Demand Charges	9,340	10040	7028	1116	29,340	29,060	20,180	0	816	18,020
Energy Charges	1170	1226	858	1775	2291	1476	hourly	995	1959	2483
…										

[7] Dakota Electric totals incorporate 2% discount for primary distribution service.

Subtotal of Monthly Delivery and Customer Charges	7035	8135	5777	8300	0	0	0	0	1204	34
Subtotal of Monthly Reservation and Daily Demand	9340	10040	7028	1116	29,340	20,060	20,180	5140	1244	18,020
Subtotal of Energy Charges	1170	1226	858	1775	2291	1476	hourly	995	1959	2483
TOTAL	17,545	19,401	13,663	11,191	31,631	30,536	20,180 plus hourly energy	6161	4407	20,127[8]

[8] Dakota Electric totals incorporate 2% discount for primary distribution service.

Case No. U-18255
Exhibit MCA-4

ENERGY AND ENVIRONMENTAL ANALYSIS, INC.

Final Report:

Distributed Generation Operational Reliability and Availability Database

Submitted To:
Oak Ridge National Laboratory
P.O. Box 2008
1 Bethel Valley Road
Oak Ridge, TN 37831-6065

Under Subcontract No. 4000021456

Submitted By:
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January 2004

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ES EXECUTIVE SUMMARY

ES-1 Objectives

The increased deployment of Distributed Generation (DG)/Combined Heat and Power (CHP) has been identified as a means to enhance both individual customer reliability and electric transmission and distribution system reliability. DG/CHP reliability and availability performance relates to several significant issues affecting market development. The reliability/availability profiles for DG/CHP systems can affect electric standby charges and back-up rates, the value of ancillary services offered to Independent Transmission System Operators (ISO), local grid stability and reliability, customer power delivery system reliability, and customer economics. Interest in power reliability has heightened in recent years in light of high-profile system.

This project represents the first attempt to establish baseline operating and reliability data for DG/CHP systems in more than a decade. Specific objectives of this project were to:

- Establish baseline operating and reliability data for distributed generation systems
- Identify and classify DG/CHP system failures and outages
- Determine failure modes and causes of outages
- Quantify system downtime for planned and unplanned maintenance
- Identify follow-on research and/or activities that can improve the understanding of reliability of DG/CHP technologies.

The primary deliverable of the project is a database framework populated with 121 DG/CHP units which is used to estimate the operational reliability (OR) of various DG/CHP technologies. From the data, key operational reliability (OR) measures were calculated. These objectives were accomplished with the valued participation of actual DG/CHP users and access to their operations and maintenance data.

ES-2 Technical Approach

The methodology for assessing the operational reliability of DG systems was to establish baseline operating and reliability data for DG/CHP systems through an exhaustive collection of data from a representative sample of operating facilities. Data was collected from user maintenance logs, operation records, manufacturers' data, and other available sources. The project team calculated key operational reliability indices. We then identified and classified DG system failures and outages for various types of technologies and applications. Finally, the project team assessed forced outage causes and quantified system downtimes for planned and unplanned maintenance. The final work product was a database framework of operational reliability data for DG/CHP systems that characterizes unit reliability over a two year period.

The technical approach used was based on the following guidelines:

- Operational reliability data should address a diverse set of prime mover technologies and applications
- Data collection process will have to rely heavily on user participation and their records
- Procedures for collecting, processing, and analyzing data must be tightly controlled.

The scope of work consisted of the following tasks:

- Review of Prior Work
- Identify and Select Candidate Sites
- Collect Operating Data
- Reduce and Analyze Data
- Assess Reliability
- Perform Outage Cause Assessment

The project team conducted an exhaustive review of public and private databases to screen potential sites to populate the database. Two databases in particular that were used extensively are the PA Consulting/Hagler-Bailly and Energy Information Administration databases of non-utility power plants. In a parallel effort to screen sites, the project team utilized its network of contacts at manufacturers, developers, gas utilities, associations, and packaged cogeneration players. As the databases of existing facilities become less accurate for sites less than 1 MW in size, these personal contacts were important in identifying the smaller sized sites. In addition, we mailed letters to various stakeholders.

The project team collected raw data for 121 DG/CHP units. These 121 units represented 731.33 MW of installed capacity and operated for 1,669,411 service hours. Data concerning 2,991 outage events were collected. Each event was described using a consistent equipment taxonomy (refer to Appendix B) and outage codes consistent with IEEE Standard 762. The primary sources of data included O&M log books, outage summary reports, and contractor service reports.

The project team developed a data collection plan that addressed the framework and procedures used to screen potential participants, enter data and analyze OR performance. To analyze data we developed a database framework upon which additional sites and data can be added.

The project team calculated OR measures consistent with industry practices. Measures include availability factor, forced outage rate, scheduled outage factor, service factor, mean time between forced outage, and mean down time.

ES-3 Results

The OR performance of a unit is affected by many factors including technology and operations and maintenance practices. The units in the sample were distributed into nine technology groups as follows:

Reciprocating Engines
Group 1: <100 kW
Group 2: 100 - 800 kW
Group 3: 800 kW – 3 MW

Fuel Cells
Group 4: <200 kW

Gas Turbines
Group 5: 500 kW – 5 MW
Group 6: 5 MW – 20 MW
Group 7: 20 – 100 MW

Microturbines
Group 8: <100 kW

Steam Turbines
Group 9: <25 MW

When compared to electric utility units reported by the North American Electric Reliability Council Generating Availability Data System (NERC GADS), the DG/CHP units reviewed in this project demonstrated comparable to superior OR performance. OR statistics for units are shown tables ES.1 through ES.3.

Table ES.1 – Summary Statistics for Reciprocating Engine Systems

Reciprocating Engines	<100kW			100-800 kW			800-3000 kW		
Number Sampled	14			8			18		
	Min.	Avg.	Max.	Min.	Avg.	Max.	Min.	Avg.	Max.
Availability (%)	96.27	97.93	99.00	84.55	95.99	99.93	91.14	98.22	100.00
Forced Outage Rate (%)	0.86	1.76	3.07	0.00	1.98	5.05	0.00	0.85	6.63
Scheduled Outage Factor (%)	0.26	0.73	1.33	0.07	2.47	14.22	0.00	1.12	3.42
Service Factor (%)	68.20	75.11	79.60	2.06	51.76	95.43	1.50	40.59	91.39
Mean Time Between Forced Outages (hrs)	505.96	784.75	1376.60	361.18	1352.26	4058.71	263.00	3582.77	14755.30
Mean Down Time (hrs)	7.29	13.71	24.21	12.50	50.66	173.05	0.00	27.06	91.91

Table ES.2 – Summary Statistics for Gas Turbine Systems

Gas Turbines	0.5-3 MW			3-20 MW			20-100 MW		
Number Sampled	11			21			9		
	Min.	Avg.	Max.	Min.	Avg.	Max.	Min.	Avg.	Max.
Availability (%)	88.88	97.13	100.00	88.56	94.97	99.60	86.33	93.53	99.45
Forced Outage Rate (%)	0.00	2.89	18.84	0.00	2.88	9.07	0.00	1.37	6.63
Scheduled Outage Factor (%)	0.00	0.99	4.57	0.00	2.39	11.44	0.00	5.14	13.50
Service Factor (%)	5.33	57.93	97.27	6.26	82.24	99.01	70.27	88.74	99.45
Mean Time Between Forced Outages (hrs)	765.62	2219.72	4318.00	216.77	1956.46	15298.00	536.00	3604.62	17424.00
Mean Down Time (hrs)	0.17	65.38	325.09	2.77	68.63	501.75	21.29	75.30	288.50

Table ES.3 – Summary Statistics: Fuel Cells and Steam Turbines

Other Technologies	Fuel Cells <200kW			Steam Turbines <25MW		
Number Sampled	15			25		
	Min.	Avg.	Max.	Min.	Avg.	Max.
Availability (%)	42.31	76.84	95.04	72.37	92.02	99.82
Forced Outage Rate (%)	4.31	22.94	57.51	0.00	2.34	16.41
Scheduled Outage Factor (%)	0.48	0.92	1.23	0.00	6.01	27.63
Service Factor (%)	42.27	74.01	92.21	3.37	81.12	99.65
Mean Time Between Forced Outages (hrs)	1416.71	2004.47	2696.33	120.18	5317.73	29585.00
Mean Down Time (hrs)	66.92	369.24	1686.83	5.51	292.06	4848.00

During the course of the project, specific units were observed to exhibit both very good to poor OR performance. In almost all technology groups, subsystems other than the prime movers themselves contributed significantly to occurrence of forced outage events. Many events that occur are the result of random equipment failures expected of any complex power system. Other events may be nonrandom in nature, indicating problems that may relate to issues pertaining to the unit design or installation. This project did not result in the identification of any such systemic problems. Most failures within technology groups appear to be random occurrences of short duration.

ES-4 Conclusions and Recommendations

The database is intended to establish a baseline of OR data on DG/CHP and allow current and potential users to benchmark reliability. The methodology and framework for recording and analyzing data is straight forward, repeatable and consistent with industry standards. It should be noted that the data reviewed for this project is only for 2000-2002 time period. The database does not include large samples in all technology groups. It is structured to accommodate more units and technology groups in a follow-on effort. Future periodic updating and maintenance on a regular basis will ensure continued usefulness and increase the confidence in the measures calculated.

The DG/CHP Reliability and Availability Database provides a general framework for recording operating data and analyzing OR performance. It provides a solid foundation for future improvements and enhancements. Recommended improvements to the database framework include:

- Add additional units in under-represented technology groups to improve the robustness of the data
- Update data on an annual basis to include years of operation beyond the original 2000-2002 period
- Include microturbines with at least two years of operations (not including R&D demonstration) along with fuel cells with similar operating history in a separate database pertaining to emerging DG/CHP technologies

Any follow-up effort needs an efficient site identification and data collection process. For example, monthly data submission by site operators with secure web-based data entry system would reduce the labor costs associated with data collection substantially.

1 INTRODUCTION

This report documents the results of an 18 month project entitled, "Distributed Generation Market Transformation Tools: Distributed Generation Reliability and Availability Database," sponsored by Oak Ridge National Laboratory (ORNL), Energy Solutions Center (ESC), New York State Energy Research and Development Authority (NYSERDA), and Gas Technology Institute (GTI).

Using operations and maintenance field data provided by distributed generation (DG)/combined heat and power (CHP) project operators, owners, and developers, the project team analyzed the operational reliability (OR) performance of various onsite generation technologies. OR generally refers to the reliability, availability, and maintainability attributes of a process system and its components. Specifically, the project team analyzed event histories for 121 DG/CHP units over a two-year time period between 2000 and 2002. A data collection and management software tool was developed as well as a database. This project represented the first attempt to establish baseline operating and reliability data for DG/CHP systems in more than a decade.

Using the raw data collected, the project team calculates summary level OR statistics for 121 units within specific technology groups. Technologies assessed included reciprocating engines, gas turbines, fuel cells, and steam turbines. The methodology and OR measures used in this project are consistent with established industry standards. The results of this project provide various stakeholders with insights to the actual OR performance of onsite power generation systems. The first version of this database provides a solid foundation upon which additional units can be added or periodic annual updating of data can be performed in the future.

The following chapters of this report explore and characterize, in turn:

- DG/CHP reliability background;
- technical approach used in the development of the reliability and availability database;
- summary operational and reliability data collected in this project;
- breakdown and analysis of event causes, and;
- Conclusions and recommendations.

2 BACKGROUND

2.1 Reliability and DG/CHP

Distributed Generation (DG) is projected to grow in importance in industrial markets. Distributed Generation represents significant opportunities for industrial customers to reduce their energy costs, improve reliability of electric service, improve their productivity by reducing costly power outages, and increase energy efficiency and reduce emissions through recovering waste heat in combined heat and power (CHP) applications.

The U.S. Department of Energy (DOE) and Oak Ridge National Laboratory (ORNL) are leaders in the development of efficient, clean DG technologies for industrial customers through partnerships with industry. As part of these efforts, DOE developed a strategy to address key barriers that must be overcome in order to accelerate the deployment of DG technologies into the industrial sector. DOE and ORNL identified the need for improved information on DG/CHP system reliability and availability. This information would allow end-users, developers and DOE to better identify and evaluate DG opportunities that provide the greatest benefit to all stakeholders. Consistent with their respective plans to accelerate the development of the CHP market, New York State Energy Research and Development Authority, Energy Solutions Center, and Gas Technology Institute cofunded the project.

2.1.1 Existing CHP Market

There are approximately 77,000 MW of CHP capacity in the United States today. This is shown in Table 2.1. The U.S. Department of Energy and others project significant growth in onsite power generation over the next decade. A key to sustaining this growth and accelerating general acceptance of onsite power generation is the achievement of high levels of reliability across all major DG/CHP technology markets.

Table 2.1 - Installed CHP by Sector

	Installed CHP Capacity by Sector (MW)			
Prime Mover	Industrial	Commercial	Other	Total
Boiler/Steam Turbine	2,336	20,080	1,595	24,011
Combined Cycle	2,589	33,939	736	37,264
Combustion Turbine	2,782	8,812	2,843	14,438
Recip Engine	818	330	37	1,184
Other	35	170	1	206
Total	8,560	63,330	5,212	77,102

Source: Energy and Environmental Analysis/Energy Nexus Group, Hagler Bailly Independent Power Database

2.1.2 Value of Operational Reliability

Distributed generation/combined heat and power (DG/CHP) are expected to play a significant role in the energy industry for the next decade. Factors affecting growth include fuel price stability, installed capital costs, and the ability of the user to generate energy when needed, i.e., operational reliability. Stakeholders in the developing DG/CHP market need assurance that power can be delivered reliably and at acceptable costs. Interruptions in service have a considerable affect on the revenue cash flow and/or cost savings from an onsite power project.

2.2 Project Objectives

The increased deployment of Distributed Generation (DG)/Combined Heat and Power (CHP) has been identified as a means to enhance both individual customer reliability and electric transmission and distribution system reliability. DG/CHP reliability and availability performance relates to several significant issues affecting market development. The reliability/availability profiles for DG/CHP systems can affect electric standby charges and back-up rates, the value of ancillary services offered to Independent Transmission System Operators (ISO), local grid stability and reliability, customer power delivery system reliability, and customer economics. Interest in power reliability has heightened in recent years in light of high-profile system.

Specific objectives of this project were to:

- Establish baseline operating and reliability data for distributed generation systems
- Identify and classify DG/CHP system failures and outages
- Determine failure modes and causes of outages
- Quantify system downtime for planned and unplanned maintenance
- Identify follow-on research and/or activities that can improve the understanding of reliability of DG/CHP technologies.

The primary deliverablse of the project is a database framework populated with 121 DG/CHP units which is used to estimate the operational reliability (OR) of various DG/CHP technologies. From the data, key operational reliability (OR) measures were calculated. These objectives were accomplished with the valued participation of actual DG/CHP users and access to their operations and maintenance data.

2.3 Project Workscope

The methodology for assessing the operational reliability of DG systems was to establish baseline operating and reliability data for DG/CHP systems through an exhaustive collection of data from a representative sample of operating facilities. Data was collected from user maintenance logs, operation records, manufacturers' data, and other available sources. The project team calculated key operational reliability indices. We then identified and classified DG system failures and outages for various types of technologies and applications. Finally, the project team assessed forced outage causes and quantified system downtimes for planned and unplanned maintenance. The final work product was a database framework of operational reliability data for DG/CHP systems that characterizes unit reliability over a minimum two-year period. This database can be augmented with additional sites in the future or be improved to allow for additional operating data to be added on a regular basis, e.g., monthly.

The database will allow individual DG facility managers to better understand reliability and availability performance of their particular units and also determine how their facilities compare with other DG resources. Detailed information on DG reliability and availability performance will enable potential DG users to make a more informed purchase decision, and will help policy makers quantify potential grid system benefits of customer-sited DG.

The workscope consisted of the following tasks:

- Review of Prior Work
- Identify and Select Candidate Sites
- Collect Operating Data
- Reduce and Analyze Data
- Assess Reliability
- Perform Forced Outage Cause Assessment

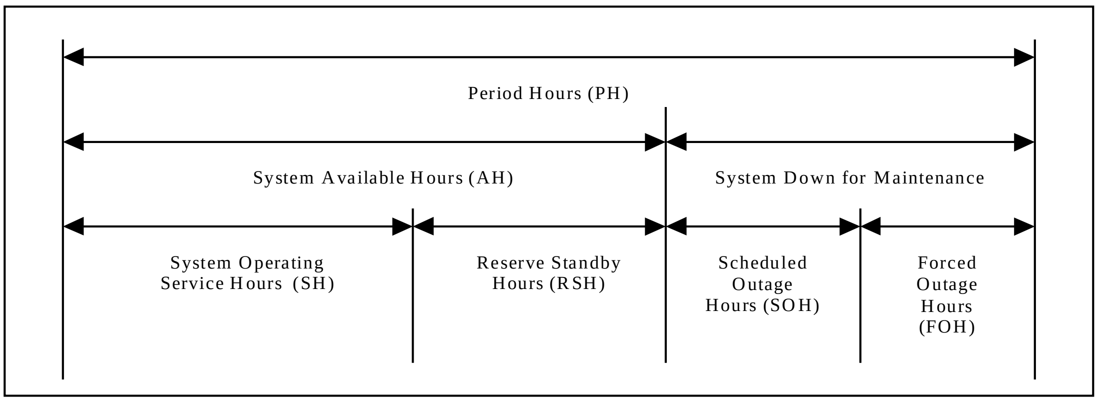
2.4 Operational Reliability Terms and Definitions

A generation unit can reside in one of three independent states. Those states are:

- Operating and producing electrical or thermal energy
- Not operating due to planned or unplanned maintenance
- Not operating, but capable of energy production (reserve standby)

These states are shown in Figure 2.1 together with the calculations used to determine OR performance. The operational reliability measures shown in Figure 2.1 are consistent with ANSI/IEEE Standard 762 *Standard Definitions for Use in Reporting Electrical Generating Unit Reliability, Availability, and Productivity*. IEEE Standard 762 contains 66 reliability related terms and 25 OR performance indices (none of which is explicitly named "reliability").

Figure 2.1 – Operational Reliability Terms and Definitions



Reliability Performance Indices	Formula
Period of Demand (POD): Measures the time the unit was planned to operate.	POD = PH - RSH- SOH
Availability Factor (AF, %): Measures, on a percent basis, the unit's "could run" capability. Impacted by planned and unplanned maintenance.	$AF = \frac{(PH - SOH - FOH) * 100}{PH}$
Forced Outage Rate (FOR, %): Measures portion of downtime due to unplanned factors.	$FOR = \frac{FOH * 100}{(SH + FOH)}$
Scheduled Outage Factor (SOF, %): Measures percent of time set aside for planned maintenance.	$SOF = \frac{SOH * 100}{PH}$
Service Factor (SF, %): Percent of total period hours the unit is on-line – varies due to site-related or economic factors.	$SF = \frac{SH * 100}{PH}$
Mean Time Between Forced Outages (MTBFO): Measures the nominal time between unscheduled forced outages.	$MTBFO = \frac{SH}{\text{\# Forced Outages}}$
Mean Down Time (MDT): Measures the nominal duration the unit is down during maintenance events.	$MDT = \frac{SOH + FOH}{\text{\# Forced Outages + \# Plant Outages}}$

3 TECHNICAL APPROACH

3.1 Introduction

The methodology for assessing the operational reliability of DG systems was to establish baseline operating and reliability data for DG/CHP systems through an exhaustive collection of data from a representative sample of operating facilities. Data was collected from user maintenance logs, operation records, manufacturers' data, and other available sources. The project team calculated key operational reliability indices. We then identified and classified DG system failures and outages for various types of technologies and applications. Finally, the project team assessed forced outage causes and quantified system downtimes for planned and unplanned maintenance. The final work product was a database framework of operational reliability data for DG/CHP systems that characterizes unit reliability over a two year period.

The technical approach used was based on the following guidelines:

- Operational reliability data should address a diverse set of prime mover technologies and applications
- Data collection process will have to rely heavily on user participation and their records
- Procedures for collecting, processing, and analyzing data must be tightly controlled.

3.2 Review Prior Work

The project team conducted a review of the methodologies of data collection and reliability assessment used in several previous studies. In addition, GTI was able to provide programming support for a consistent and uniform approach to the collection of data and its management based on its prior work in cogeneration system reliability.

3.2.1 Key References

While many sources were identified in the existing body of work on power plant reliability, including those by the Electric Power Research Institute, North American Reliability Council/Generating Availability Data System, and the US Army, several key references represent the prior work most directly applicable to the objectives and methodology of this project. They include the following:

- GRI/ARINC Cogeneration Operational Reliability Database
- FOREMAN Software User Guide – An Operations and Maintenance Data Manager and Reliability Reporting System
- IEEE Recommended Practice for Design of Reliable Industrial and Commercial Power Systems

- ANSI/IEEE 762 Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity
- Reliability Survey of 600-1800 kW Diesel and Gas-Turbine Generating Units, ARINC, IEEE ICPSD 89-02

As a result of the review of prior work, a preliminary database structure was developed. The structure will consist of three primary components. The three components are based on Facility Information, Unit/Subsystem/Component Information, and Event Descriptions. The review of prior work also helped in developing the unit selection criteria and the determination of desireable hours of operation in order to ensure confidence in the validity of the operational reliability indices calculated. This is described in the unit selection section below.

3.3 Candidate Screening and Selection

The objective of the screening process was to identify candidate units that will be considered for inclusion in the project. The project team conducted an exhaustive review of public and private databases to screen potential sites to populate the database. Two databases in particular that were used extensively are the PA Consulting/Hagler-Bailly and Energy Information Administration databases of non-utility power plants. In a parallel effort to screen sites, the project team utilized its network of contacts at manufacturers, developers, gas utilities, associations, and packaged cogeneration players. As the databases of existing facilities become less accurate for sites less than 1 MW in size, these personal contacts were important in identifying the smaller sized sites. In addition, we mailed letters to various stakeholders. The text of a targeted letter to contacts at manufacturers, developers, gas utilities, associations, and packaged cogeneration players is shown in Appendix A.

Sites from the databases as well as those identified by contacts were contacted via telephone to screen the possibility of inclusion in the final database.

3.3.1 Screening Process

The development of a final screening questionnaire for potential sites was a two step process. Initially the following set of questions was used to determine the suitability of the candidate units.

Basic Questions for screening

General

1. Facility Name
2. Contact/phone/fax/email
3. Prime mover models/# of units
4. Fuel
5. Thermal application
6. Utility connected or isolated
7. Facility or contractor maintained

8. Operation baseload/cycling/peak/standby

Questions on Data Availability – Are these tracked and documented?

1. Maintenance logs
2. Monthly operating hours data
3. Number of unit starts
4. Records of scheduled maintenance
5. Records of corrective maintenance

Operations and Maintenance Questions – Is there an approximate understanding of these measurements

1. What are the approximate service factors for plant units?
2. What percentage of the time does each unit run?
3. How many times per month does each unit shut down for corrective maintenance?
4. How many times are the units started per month?
5. What are the approximate annual scheduled outage hours?
6. Who performs the scheduled maintenance?

Design Questions

1. Have equipment modifications been made? Describe.
2. Are emission control devices used? Describe.
3. What is nameplate electrical output rating?
4. What is thermal output? If applicable

Questions about administration

1. Can ONSITE Energy obtain permission to review maintenance and operating records?
2. Will plant transmit (mail or electronic) copies of records to ONSITE?
3. Will a site visit be required to review records?

Follow-up Actions and recommendation to include in DB

This approach resulted in being too time intensive in a trial, especially considering that thousands of potential sites exist in the databases being used.

A revised screening that was effectively reduced to validating the plant information the project team has and a series of yes and no questions was developed. Those questions as well as a project background “preamble” follow.

Introduction

On behalf of the U.S. Depart of Energy and Oak Ridge National Laboratory, Energy Nexus Group, a subsidiary of ONSITE Energy, is developing an operational reliability and availability database for on-site generation technologies.

The final work product will be a database of operational reliability data for DG/CHP systems. The database will allow individual DG/CHP facility managers to better understand reliability and availability performance of their particular units and also determine how their facilities compare with other resources. Detailed information on DG/CHP reliability and availability performance will enable potential users to make a more informed purchase decision, and will help policy makers quantify potential grid system benefits of customer-sited generation.

We are seeking your assistance in identifying onsite generation sites with at least two years of operating experience to populate the database. We are currently in the process of identifying and screening potential sites to populate the database and could use your assistance.

Your facility was identified as a potential site (at the recommendation of a manufacturer of your equipment, packager/distributor/project developer, or through a review of databases of existing DG or CHP facilities).

To be in the final database population we will ultimately need the following essential data:

- monthly operations reports that describe unit electric generation and engine service hours
- maintenance log books and service reports that describe planned and unplanned outage maintenance and outage durations

At this point in time we are screening candidate sites and have just a basic set of questions.

Do you have some time to answer some questions?

General (in some cases validate the information from our databases)

1. Facility Name
2. Contact/phone/fax/email
3. Prime movers/# of units
4. Fuel
5. Thermal application (CHP)/power only
6. Years of operation

Yes/No Questions on Data Availability – Are they tracked and documented?

1. Is there a central data source for maintenance information such as maintenance logs?
2. Do you collect maintenance data?
3. Do you collect operating data?
4. Do you record all outages planned and unplanned?
5. Do you keep logs for scheduled maintenance?
6. Do you track maintenance time and corrective maintenance actions in the case of forced outages?
7. Is there a maintenance program currently in place?
8. Can ONSITE Energy obtain permission to review maintenance and operating records?
9. Will plant transmit (mail or electronic) copies of records to ONSITE?
10. Will a site visit be required to review records?

Follow-up Actions and recommendation to include in DB

More than 2000 potential candidate sites were screened and reduced to 179 sites representing 377 DG/CHP units.

3.3.2 Unit Selection Criteria

Of the nearly 400 DG/CHP units that passed our screening process, 121 units were ultimately included in the first version of the database. Units were eliminated due to lack of data, excessive time required of plant staff to assemble data, and budget constratints of the project. Additonal units can be added to the database framework in the future. The breakdown of the 121 units is shown Figure 3.1 and 3.2.

Figure 3.1 - Distribution of Sample by Technology by Units (n=121)

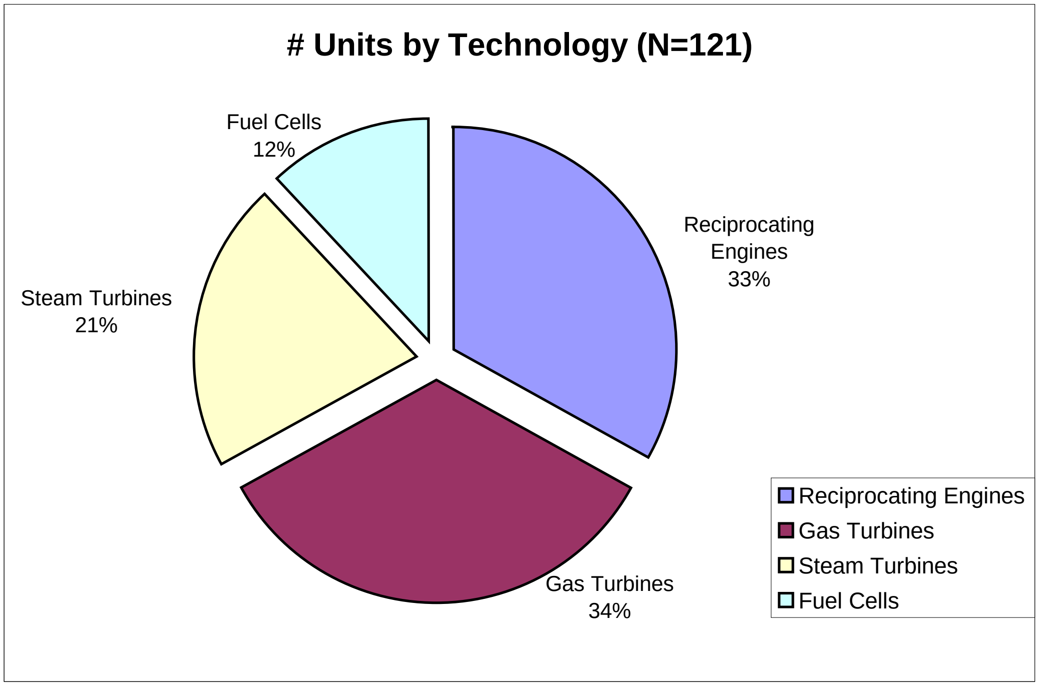
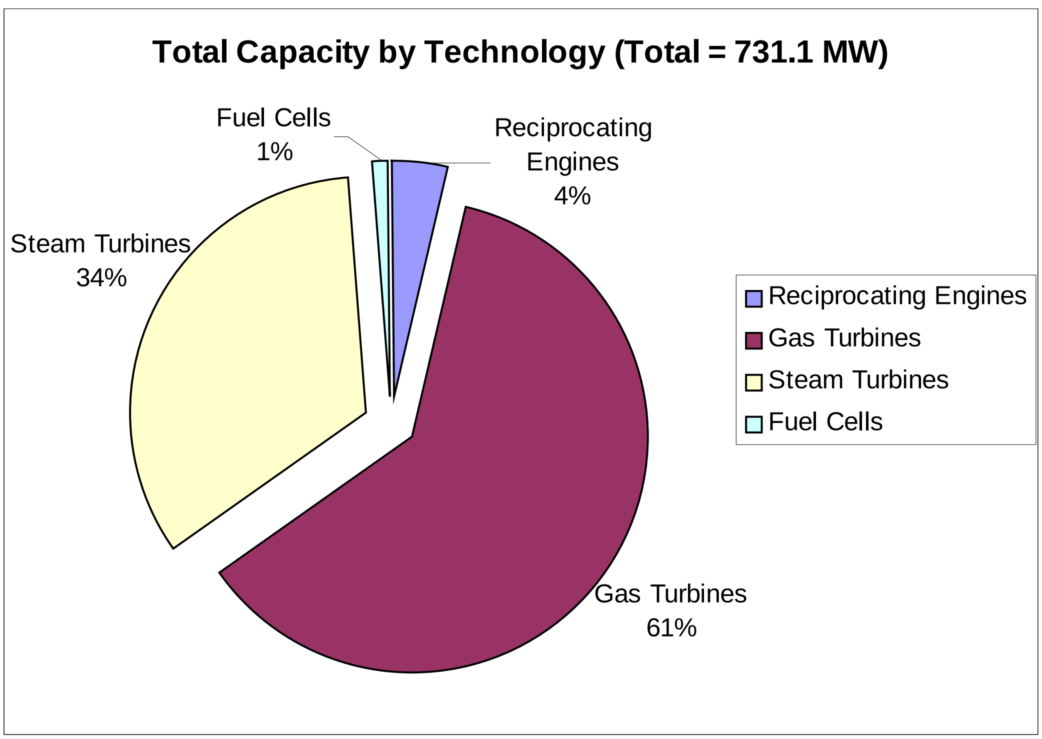


Figure 3.2 - Distribution of Sample by Technology by Capacity



Originally, units were intended to be selected based on the following criteria:

- Technology group
- Two full years of planned operation from 2000-2002
- Number of units at each site
- Completeness of O&M data
- Geography
- Customer sector (Industrial, Commercial, or Institutional)
- Willingness to cooperate and provide data

Nine Technology Groups were identified. They are listed below.

Reciprocating Engines
Group 1: <100 kW
Group 2: 100 - 800 kW
Group 3: 800 kW – 3 MW

Fuel Cells
Group 4: <200 kW

Gas Turbines
Group 5: 500 kW – 5 MW
Group 6: 5 MW – 20 MW
Group 7: 20 – 100 MW

Microturbines
Group 8: <100 kW

Steam Turbines
Group 9: <25 MW

The project team identified units in all technology groups that met the selection criteria with the exception of Group 8, microturbines. We believe this is due to the fact that units installed and operating by January 2000, the cut-off date for the required two years of operation to be included in this project were either pre-commercial or first generation microturbines. Developers and users would have had to provide data and characterize operational reliability of this class of technology based on units that would not be representative of the products that would ultimately be used in the market. They were justifiably reluctant to participate on this basis. In fact this was seen in the fuel cell data collected and analyzed for this project. Fuel cell operational reliability indices calculated were significantly lower than all other technology groups and what fuel cell manufacturers typically quote. Availability was greatly affected by downtime associated with unusually long delays (e.g., maintenance personnel response, availability of replacement parts, site operations) and not related to typical operation. For that reason, the project team elected not to collect data on microturbines at this time, but to structure the data collection software and database to easily accommodate microturbine data in the future.

Based on *IEEE Recommended Practice for Design of Reliable Industrial and Commercial Power Systems* and *GRI Report 93/0020 Reliability of Natural Gas Cogeneration Systems* two years of operating service per unit were desired in order to be considered for the database and calculate representative operational reliability indices. Two years of service corresponds to a 90% confidence that calculated indices are within 30% of the true unknown values.

The project team attempted to collect data on at least ten units in each technology group. We failed to do so for Technology Groups 2 and 7. The database was structured so that additional units can be added at some future date if follow-up activities are pursued.

3.4 Data Collection and Management Plan

The project team developed a data collection and management plan that addressed field data collection procedures, data sources, and analysis methods. Procedures for collecting, processing, and analyzing data had to be tightly controlled. GTI developed a Microsoft Access® based data collection and management software tool. The structure and description of the data collection software is in Appendix B. In addition to meeting the needs of the project team, the data input format had to be simple and consistent with user records and maintenance logs. Required operating data included:

- Monthly operation reports that describe unit service hours
- Maintenance log books
- Service reports that describe planned and unplanned outage maintenance
- Outage summary reports
- Contractor service reports

The data collection software was comprised of three primary components along with reporting and exporting features that allowed for post processing and analysis. The components consisted of the following:

- Plant Configuration – Characterize design and equipment features of each plant
- Subsystem Operations – Prime mover subsystem operations data for each plant
- Event Description – History of planned and unplanned maintenance, downtime duration, downtime cause, failure modes
- Reports – Summary reports for data contained in Plant Configuration, Subsystem Operations, and Event Description.

3.5 Collection of Raw Data

Based on the review of prior work and an initial round of feedback from potential candidate facilities, a set of desirable data collection parameters was identified. They are presented in Tables 3.1-3.4. The project team collected the described data while providing assurance to the participating facilities that they would not be mentioned by name in the project final report or database. Manufacturers and model numbers of units are also anonymous. This was required to ensure cooperation of manufacturers.

Each event relates to specific operating unit and is described by the type of outage, date of occurrence, outage duration, system/component cause, and the maintenance performed. From this detailed data, the project team is able to accurately derive operational reliability statistics.

Table 3.1 - Facility/Plant Information

Field Name	**Field Description**
Facility Name	Customer Site Name
Facility Code	Unique Facility Code Number Assigned
Facility Location	City/State
Contact	Name and Contact Information
Plant Type	Based on Primary Prime Mover Technology
Primary Fuel Type	Primary Fuel Type
Net Maximum Facility Capacity	Net Maximum Capacity for Plant in kW
Thermal Recovery Unit	Type of Heat Recovery

Table 3.2 - Unit Information

Field Name	**Field Description**
Code or Abbreviation	Technology Group and Subcategory
Unit Code	Unique Unit Code Number Assigned
Gross Output (kW)	Unit Gross Maximum Capacity in kilowatts
Thermal Rating (MMBtu/h)	Thermal Rating of Unit in MMBtu per Hour
Emissions Control	Emissions Control System Code
Modifications/Comments	Comment Field for Modifications to Engine Generator Unit

Table 3.3 - Unit Monthly Generation History Data

Field Name	**Field Definition**
Unit Code	Unique Unit Code
Date (MM/YY)	Date
Total Service Hours	Total run hours at any electrical output
Number of Attempted Starts	Number of starts attempted to bring the unit form shutdown to synchronism (repeated failures to start for the same cause without attempting corrective action are considered a single attempt)
Number of Successful Starts	Number of times the unit successfully started and synchronized

Table 3.4 - Event Log Data

Unit	Event Number Assigned	Start date/time	End date/time	Event Code	Derating (%)	Type of Maintenance	Event Maintenance is related	System Code	Component Code	Corrective Maintenance Taken (Y/N)	Corrective Action Code	Comments

There was a good deal of feedback from candidate sites regarding the event data being solicited. What the project team found was that it is difficult to document causes of outages. The host facilities in many cases do not document them well. In several instances, the detailed event history is just in the operator's memory and not consistently documented (in some cases causes aren't documented at all). Some manufacturers were reluctant to share the data. The information needed at a minimum to calculate the key statistics are when events (e.g., forced outages) actually occurred and their frequency relative to service hours. The project team had to compromise on the cause data available for event cause assessment. We were unable to obtain causal data for the entire set of events in our sample. A follow up effort may be asking the population to track and document better on a going forward basis.

Data was obtained through electronic mail, fax, standard mail, telephone interviews, and site visits. The problem most frequently encountered in obtaining data was the level of effort required by plant staff to assemble and reproduce the necessary records.

3.6 Post Processing of Operational Reliability Data

The project team calculated six operational reliability measures for each of the units in the sample from operating and event data collected for the project. These measures included availability factor (AF), forced outage rate (FOR), scheduled outage factor (SOF), service factor

(SF), mean time between forced outages (MTBFO), and mean down time (MDT). These indices were defined in the background section of this report.

The data on operations and outage events was arranged in a consistent record format. Data reduction was performed by examining operating data for each unit (e.g., period hours, operating hours, starts and start failures) and events in the operating and maintenance records to identify the timing, duration, and cause for each unit outage.

For each technology group, statistical tests of variance were conducted. There was wide variation in the calculated unit level measures within technology groups. Variations in calculated indices were generally attributed to the presence or absence of long downtime events (usually within the technology group) that were specific to the project site and characteristic of a design related factor.

Average OR indices for units of the same technology are calculated by first summing the data for each term in the equation for *n* units composing each technology group. For example, the average FOR is calculated as follows:

$$FOR = \frac{\sum_{i=1}^{n} FOH}{\sum_{i=1}^{n} SH + \sum_{i=1}^{n} FOH} \times 100$$

3.7 Failure Cause Assessment

The project team characterized the frequency and duration of planned and forced events. Failure cause assessment was conducted for forced outage events. The frequency and duration of forced outage events caused by system/components was tabulated and assessed. This was done for all technology groups but Technology Group 4, fuel cells. Fuel cell operational reliability indices calculated were significantly lower than all other technology groups and what fuel cell manufacturers typically quote. Availability was greatly affected by downtime associated with unusually long delays (e.g., maintenance personnel response, availability of replacement parts, site operations) and not related to typical operation. These unusually long delays and the attribution of those long events to specific systems/components would have unfairly characterized the causes of those events and their typical duration.

As mentioned previously, the project team found it was difficult to document causes of outages. The host facilities in many cases do not document them well. In many cases, the detailed event history is just in the operator’s memory and not consistently documented (in some cases causes aren’t documented at all). There are outages in which causes are not documented. The failure cause analysis was conducted with noticeable events with not documented causal information.

4 SUMMARY OF DATABASE OPERATIONAL RELIABILITY

4.1 Introduction

This project represented the first attempt to establish baseline operating and reliability data for DG/CHP systems in more than a decade. The database developed includes 121 units representing 731.33 MW of installed capacity, operating for 1,669,411 service hours. The database covers two years of operation between 2000 and 2002 for each unit and contains descriptions of 2,991 outage events were collected. The entire database in Microsoft Access format is on the accompanying CD to this report and referred to as Appendix C. The summary reports that the Access file will generate are referred to as Appendix D.

4.2 Summary OR Performance

Tables 4.1 and 4.2 summarize the OR statistics calculated from the database by technology group and duty cycle. The technology groups were defined as:

Reciprocating Engines
Group 1: <100 kW
Group 2: 100 - 800 kW
Group 3: 800 kW – 3 MW

Fuel Cells
Group 4: <200 kW

Gas Turbines
Group 5: 500 kW – 3 MW
Group 6: 3 MW – 20 MW
Group 7: 20 – 100 MW

Microturbines
Group 8: <100 kW

Steam Turbines
Group 9: <25 MW

With the exception of Technology Group 4 (fuel cells), all technology groups demonstrated acceptable to very good OR performance. Good performance is generally considered to be 90% availability factor or higher. Fuel cell OR performance was greatly affected by downtime associated with unusually long delays and not related to typical operation. Waiting time for service or replacement parts can have a serious effect. For example, several multi-month outages due to delays in service created an inaccurate representation of fuel cell OR performance. In those specific cases the availability calculated can become more a measure of the service system than the inherent disposition of the equipment to perform.

The project team identified units in all technology groups that met the selection criteria with the exception of Group 8, microturbines. We believe this is due to the fact that units installed and operating by January 2000, the cut-off date for the required two years of operation to be included in this project were either pre-commercial or first generation microturbines. Developers and users would have had to provide data and characterize operational reliability of this class of technology based on units that would not be representative of the products that would ultimately be used in the market. They were justifiably reluctant to participate on this basis. In fact, this effect was seen in the fuel cell data collected and analyzed for this project. The decision was made not to include microturbine data at this time but to structure the database to accommodate the addition of microturbine data at a later date if so desired.

Table 4.1 – Summary Operational Reliability Statistics by Technology Group

Technology Group	n	Availability (%) Avg.	Outage Rate (%)	Outage Factor (%)	Factor (%) Avg.	Between Forced	Mean Down Time (hrs)
1	14	97.93	1.76	0.73	75.11	784.75	13.71
2	8	95.99	1.98	2.47	51.76	1,352.26	50.66
3	18	98.22	0.85	1.12	40.59	3,582.77	27.06
4	15	76.84	22.94	0.92	74.01	2,004.47	369.24
5	11	97.13	2.89	0.99	57.93	2,219.72	65.38
6	21	94.97	2.88	2.39	82.24	1,956.46	68.63
7	9	93.53	1.37	5.14	88.74	3,604.62	75.30
9	25	92.02	2.34	6.01	81.12	5,317.73	292.06
Entire Sample	121	93.09	4.65	2.66	70.23	2,869.83	138.53

Table 4.2 – Summary Operational Reliability Statistics by Duty Cycle

Duty Cycle	Service Factor Range	N	Availability (%) Avg.	Forced Outage Rate (%) Avg.	Scheduled Outage Factor (%) Avg.	Service Factor (%) Avg.	Mean Time Between Forced Outages (hrs)	Mean Down Time (hrs)
Peak	1-10%	14	99.42	0.02	0.58	2.60	456.80	22.21
Cycling	10-70%	26	88.76	10.15	2.16	54.03	2,339.48	383.19
Baseload	>70%	81	93.39	3.69	3.18	87.11	3,457.13	80.10
Entire Sample	0-100%	121	92.62	6.48	1.59	36.86	1,659.54	250.93

The breakdown by duty cycle shows good OR performance by units in all applications. Cycling average data is less impressive than the other duty cycles. This is primarily due to the fact that a number of technology group 4 units fall into this category.

With regard to very low service factor units (e.g., standby units with service factor 3 %), an additional future analysis based on starting reliability may provide improved insights. These units are characterized by approximately 100-300 hours of annual operation and service hours that range from 100 to 200 hours of maintenance and service. They have a very large percentage of their time in the state of reserve standby during which the unit is fully available but not operating. Using the same OR measures as higher service factor may not represent their reliability accurately.

4.3 Reciprocating Engine Performance

Table 4.3 presents the OR summary results for the three reciprocating engine technology groups, including average and range for all OR measures calculated. They all exhibited very good average OR performance.

Table 4.3 – Summary Statistics for Reciprocating Engine Systems

Reciprocating Engines	<100kW			100-800 kW			800-3000 kW		
Number Sampled		14			8			18	
	Min.	Avg.	Max.	Min.	Avg.	Max.	Min.	Avg.	Max.
Availability (%)	96.27	97.93	99.00	84.55	95.99	99.93	91.14	98.22	100.00
Forced Outage Rate (%)	0.86	1.76	3.07	0.00	1.98	5.05	0.00	0.85	6.63
Scheduled Outage Factor (%)	0.26	0.73	1.33	0.07	2.47	14.22	0.00	1.12	3.42
Service Factor (%)	68.20	75.11	79.60	2.06	51.76	95.43	1.50	40.59	91.39
Mean Time Between Forced Outages (hrs)	505.96	784.75	1376.60	361.18	1352.26	4058.71	263.00	3582.77	14755.30
Mean Down Time (hrs)	7.29	13.71	24.21	12.50	50.66	173.05	0.00	27.06	91.91

4.4 Gas Turbine Performance

Table 4.4 presents the OR summary results for the three gas turbine technology groups, including average and range for all OR measures calculated. They all exhibit good OR performance.

Table 4.4 – Summary Statistics for Gas Turbine Systems

Gas Turbines	0.5-3 MW			3-20 MW			20-100 MW		
Number Sampled		11			21			9	
	Min.	Avg.	Max.	Min.	Avg.	Max.	Min.	Avg.	Max.
Availability (%)	88.88	97.13	100.00	88.56	94.97	99.60	86.33	93.53	99.45
Forced Outage Rate (%)	0.00	2.89	18.84	0.00	2.88	9.07	0.00	1.37	6.63
Scheduled Outage Factor (%)	0.00	0.99	4.57	0.00	2.39	11.44	0.00	5.14	13.50
Service Factor (%)	5.33	57.93	97.27	6.26	82.24	99.01	70.27	88.74	99.45
Mean Time Between Forced Outages (hrs)	765.62	2219.72	4318.00	216.77	1956.46	15298.00	536.00	3604.62	17424.00
Mean Down Time (hrs)	0.17	65.38	325.09	2.77	68.63	501.75	21.29	75.30	288.50

4.5 Fuel Cell and Steam Turbine Performance

Table 4.5 presents the OR summary results for the fuel cell and steam turbine technology groups, including average and range for all OR measures calculated. The steam turbine group exhibits slight lower OR performance than the reciprocating engine and gas turbine technology groups. Fuel cell operational reliability indices calculated from our sample were significantly lower than all other technology groups and what fuel cell manufacturers typically quote. Availability, forced outage rate and mean down time was greatly affected by downtime associated with unusually long delays (e.g., maintenance personnel response, availability of replacement parts, site operations) and not related to typical operation.

Table 4.5 – Summary Statistics: Fuel Cells and Steam Turbines

Other Technologies	Fuel Cells <200kW			Steam Turbines <25MW		
Number Sampled		15			25	
	Min.	Avg.	Max.	Min.	Avg.	Max.
Availability (%)	42.31	76.84	95.04	72.37	92.02	99.82
Forced Outage Rate (%)	4.31	22.94	57.51	0.00	2.34	16.41
Scheduled Outage Factor (%)	0.48	0.92	1.23	0.00	6.01	27.63
Service Factor (%)	42.27	74.01	92.21	3.37	81.12	99.65
Mean Time Between Forced Outages (hrs)	1416.71	2004.47	2696.33	120.18	5317.73	29585.00
Mean Down Time (hrs)	66.92	369.24	1686.83	5.51	292.06	4848.00

4.6 Comparison to Central Station Operational Reliability Performance

The North American Reliability Council Generating Availability Data Service (NERC GADS) was created to provide utilities with information on OR perfomance of electric generating units and their related equipment. One of the primary reports that NERC GADS produces is the *Generating Availability Report* (GAR). The GAR reports OR data over a cumulative five years, annually. The statistics in the GAR are calculated from data that electric utilities report voluntarily to (NERC GADS). Operating histories for more than 4,400 electric generating units reside in GADS. Data are reported by 178 utilities in the United States and Canada, representing investor-owned, municipal, state, cooperative, provincial, and federal segments of the industry. NERC aggregates these data and presents the results annually in its GAR. Table 4.6 shows 1997-2001 OR performance data for five central station technologies. Data on onsite generation technologies assessed for this project are comparable or better than the most recent NERC GAR OR data on central station technologies.

Table 4.6 NERC GAR 1997-2001 Summary OR Statistics

OR Measure	Fossil (Boiler)	Nuclear	Gas Turbine	Combined Cycle	Hydro
# of Units	1524	128	887	80	823
Availability Factor (%)	86.66	82.87	90.31	85.85	90.62
Forced Outage Rate (%)	5.16	7.83	41.40	3.24	4.68
Scheduled Outage Factor (%)	9.59	10.09	6.36	7.64	6.53
Service Factor (%)	68.98	82.85	4.72	61.36	57.95

5 ASSESSMENT OF EVENT CAUSES

5.1 Outage Event Summary

The project team tabulated the distribution of planned and unplanned (forced) outages for each technology group. Tables 5.1 to 5.8 show the distribution between planned and forced outages and the subsystem to which they were attributed for each technology group. Note that no subsystem codes are assigned for technology group for reasons documented in previous sections of this report.

Table 5.1 - Reciprocating Engine (<100 KW) Outage Statistics

Reciprocating Engines <100 kW	System Component Code	Events	Duration (hrs)
Planned Outage	Controls	12	28.8
	Engine System	109	1,768.80
Planned Outage Total		121	1,797.60
Forced Outage	Controls	103	309.4
	Engine System	29	766
	Generator	19	450
	Heat Recovery System	38	1,117.20
	Ignition System	20	395.9
	Plant Service	35	243.3
	No Record	1	14.8
Forced Outage Total		245	3,296.50
Grand Total		366	5,094.10

Table 5.2 - Reciprocating Engine (100-800 KW) Outage Statistics

Reciprocating Engines 100-800 kW	System Component Code	Events	Duration (hrs)
Planned Outage	Engine System	4	334
	Electrical System	2	21
	Plant Service	6	14
	No Record	45	5472.9
Planned Outage Total		57	5841.9
Forced Outage	Controls	15	258.5
	Engine System	19	527
	Electrical System	3	92
	Fuel System	19	1151
	Heat Recovery System	7	383
	Plant Service	5	53
	No Record	7	414
Forced Outage Total		75	2878.5
Grand Total		132	8720.4

Table 5.3 - Reciprocating Engine (800-3,000 KW) Outage Statistics

Reciprocating Engines 800-3,000 kW	System Component Code	Events	Duration (hrs)
Planned Outage	Controls	3	1.2
	Engine System	69	1161.5
	Electrical System	1	194.3
	Fuel System	1	49
	Plant Service	404	808
	No Record	25	1339.9
Planned Outage Total		503	3553.9
Forced Outage	Controls	10	216.9
	Engine System	16	734
	Electrical System	2	8.3
	Fuel System	6	202.8
	Heat Recovery System	4	264.3
	Plant Service	9	209.2
	No Record	13	446
Forced Outage Total		60	2081.5
Grand Total		563	5635.4

Table 5.4 - Fuel Cell Outage Statistics

Fuel Cells <200 kW	System Component Code	Events	Duration (hrs)
Planned Outage	Not Accounted	101	2699
Forced Outage	Not Accounted	109	56383.8
Grand Total		210	59082.8

Table 5.5 - Gas Turbine (0.5-3.0 MW) Outage Statistics

Gas Turbine 500-3000 kW	System Component Code	Events	Duration (hrs)
Planned Outage	Combustor Section	1	44
	Electrical System	4	54.9
	Gas Turbine System	118	5038.7
	Generator	6	322.5
	Heat Recovery System	2	11.6
	Lube Oil System	3	74.9
	Fuel System	10	63.4
	No Record	62	2293.3
Planned Outage Total		206	7903.3
Forced Outage	Combustor Section	1	41.3
	Controls	64	1285.2
	Electrical System	7	55.8
	Fuel System	82	1085.5
	Gas Turbine System	165	2277.1
	Generator	8	126.3
	Heat Recovery System	20	2195.2
	Inlet Air System	2	33.5
	Lube Oil System	4	6.5
	Plant Service	92	450.3
	No Record	21	811.9
Forced Outage Total		466	8368.6
Grand Total		672	16271.9

Table 5.6 - Gas Turbine (3-20 MW) Outage Statistics

Gas Turbine 3-20 MW	System Component Code	Events	Duration (hrs)
Planned Outage	Controls	7	511.5
	Cooling Water System	1	1.9
	Electrical System	2	145.4
	Emission Controls	3	70.7
	Fuel System	2	3.8
	Gas Turbine System	27	6863.2
	Generator	5	146.8
	Heat Recovery System	6	265.3
	Inlet Air System	1	19
	Lube Oil System	2	10.9
	Plant Service	6	299.9
	No Record	145	10566
Planned Outage Total		207	18904.4
Forced Outage	Controls	20	298.3
	Cooling Water System	1	2.8
	Electrical System	21	1062
	Emission Controls	10	757
	Exhaust System	1	0.3
	Fuel System	25	138.4
	Gas Turbine System	27	72
	Generator	2	80.6
	Heat Recovery System	6	253.3
	Lube Oil System	11	131.7
	Plant Service	25	225.2
	Start Menu	2	0.6
	No Record	55	3785.2
Forced Outage Total		206	6807.4
Grand Total		413	25711.8

Table 5.7 - Gas Turbine (20-100 MW) Outage Statistics

Gas Turbine 20-100 MW	System Component Code	Events	Duration (hrs)
Planned Outage	Controls	3	438
	Electrical System	5	38.2
	Fuel System	1	6.3
	Gas Turbine System	17	1595.3
	Heat Recovery System	3	105.8
	Plant Service	18	420.1
Planned Outage Total		47	2603.7
Forced Outage	Controls	2	126
	Electrical System	2	6.3
	Fuel System	2	28.8
	Gas Turbine System	4	39.3
	Generator	2	102.7
	Plant Service	19	872.4
	No Record	2	1304.5
Forced Outage Total		33	2480
Grand Total		80	5083.7

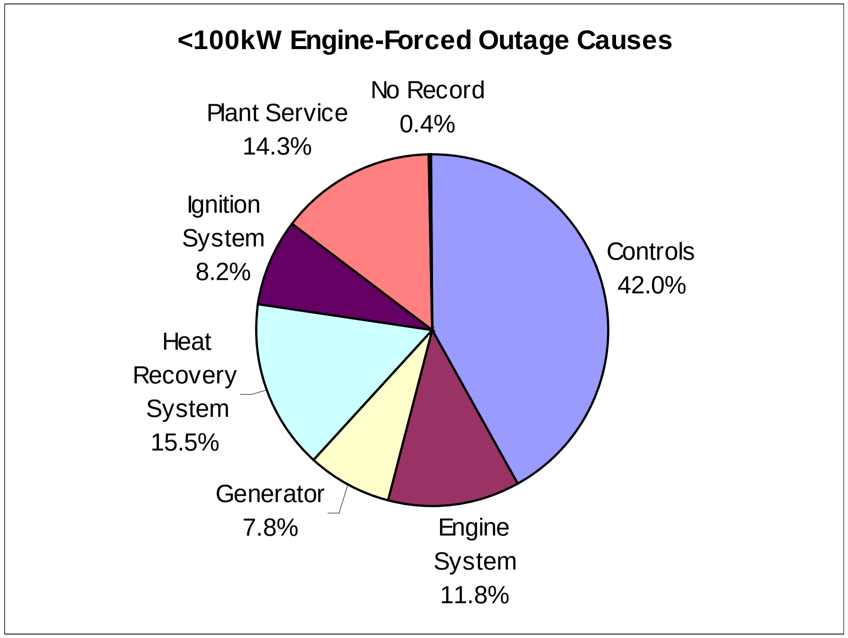
Table 5.8 - Steam Turbine (<25 MW) Outage Statistics

Steam Turbine <25 MW	System Component Code	Events	Duration (hrs)
Planned Outage	Boiler	15	2163.9
	Controls	23	3816.3
	Cooling Water System	2	31.6
	Electrical System	1	175
	Exhaust System	1	5
	Feed Water System	3	6.5
	Fuel System	11	56
	Generator	15	735.5
	Lube Oil System	3	257.8
	Plant Service	22	2017.3
	Steam Turbine System	22	10270.8
	No Record	115	12997.8
Planned Outage Total		233	32533.5
Forced Outage	Boiler	9	704.4
	Controls	29	259.6
	Cooling Water System	4	202.6
	Electrical System	13	991.5
	Exhaust System	4	27.9
	Feed Water System	5	20.1
	Fuel System	22	171.2
	Generator	16	2274.3
	Lube Oil System	3	9
	Plant Service	137	1623.8
	Steam Turbine System	55	2431.8
	No Record	22	455.3
Forced Outage Total		319	9171.5
Grand Total		552	41705

5.2 Forced Outage Assessment by Subsystem

OR data was analyzed in order to characterize the contributions of subsystems to forced outages. Figures 5.1 to 5.7 depict the outage event occurrence percent contribution and outage downtime percent contribution to forced outages by subsystem. Technology group 4 data is not present as cause of event data could not be accurately accounted due to reasons noted previously in this report.

Figure 5.1 - Outage Causes as a Percent of Occurrences and Total Downtime: <100 KW Engine Systems



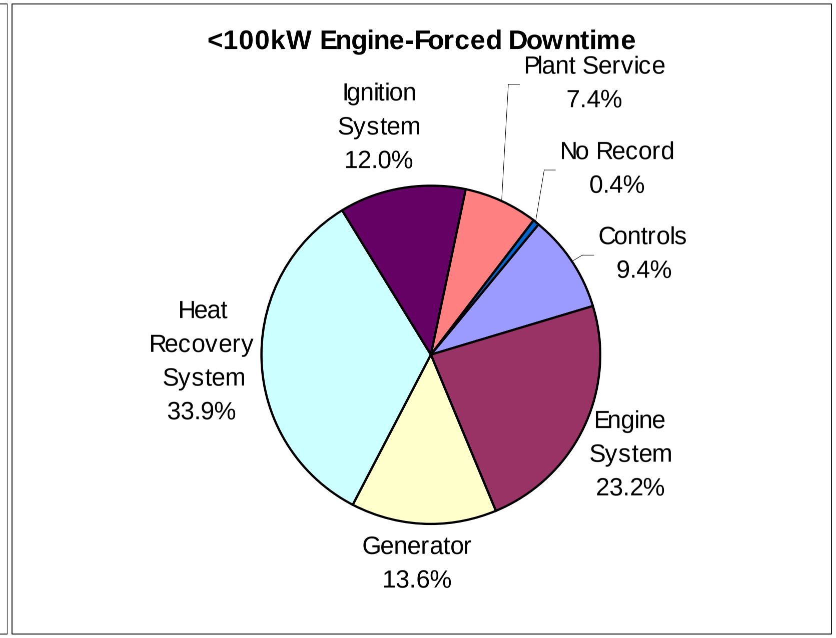
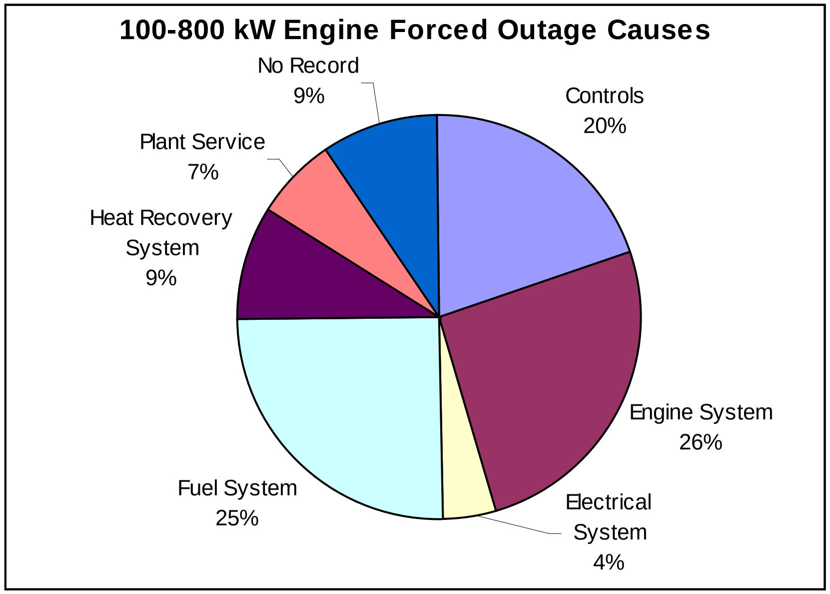


Figure 5.2 - Outage Causes as a Percent of Occurrences and Total Downtime: 100-800 KW Engine Systems



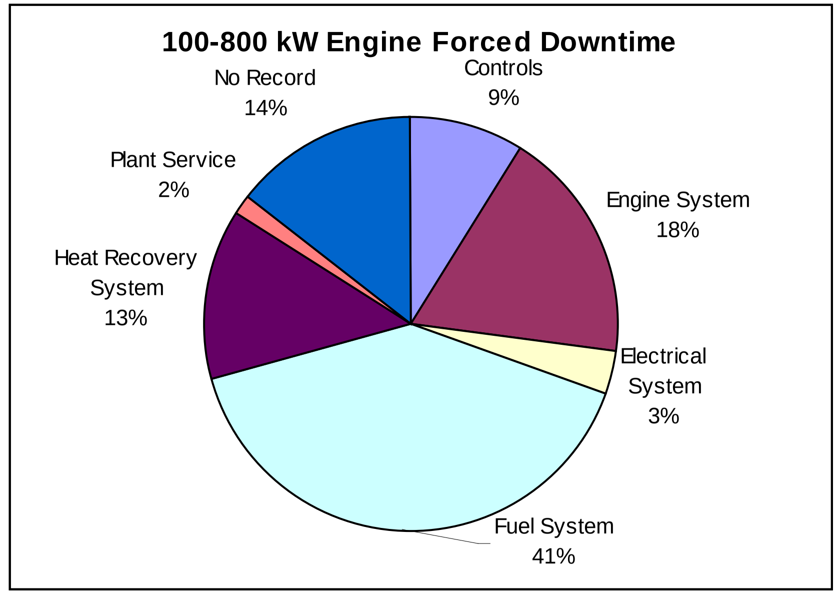
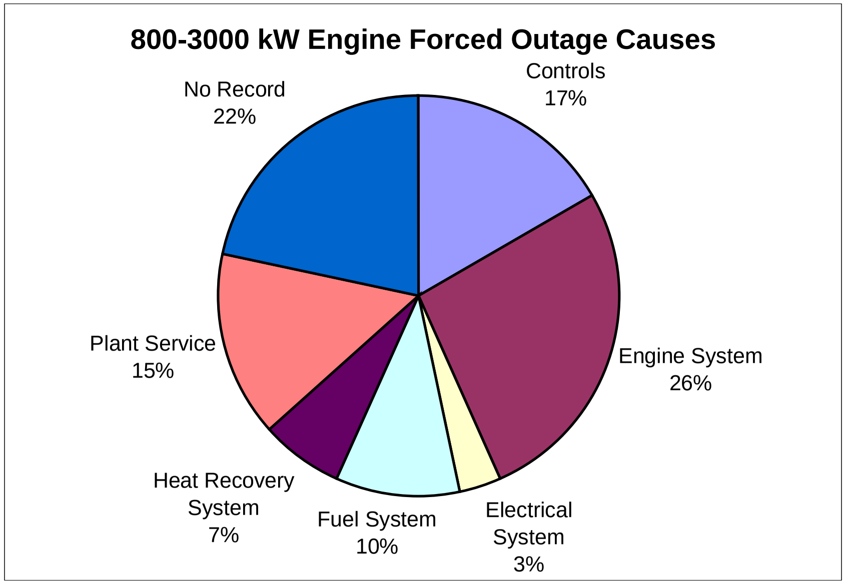


Figure 5.3 - Outage Causes as a Percent of Occurrences and Total Downtime: 800-3,000 KW Engine Systems



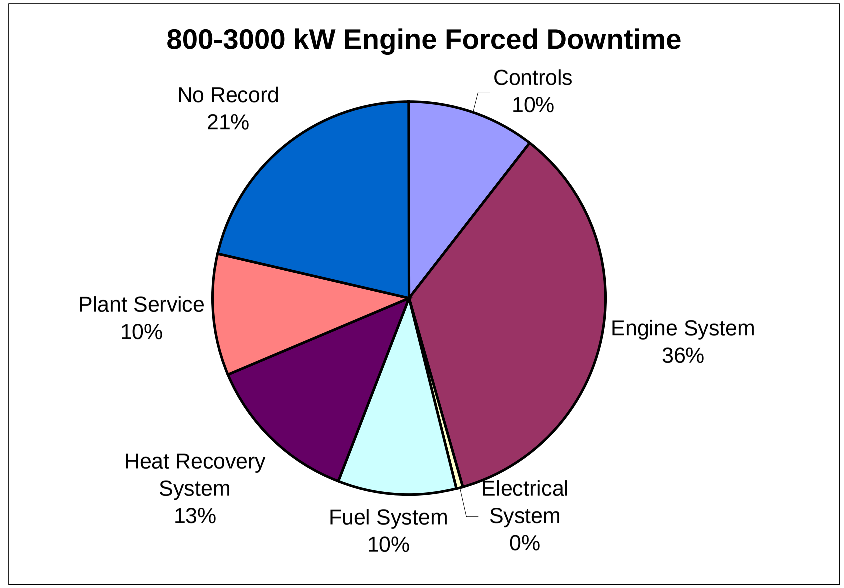
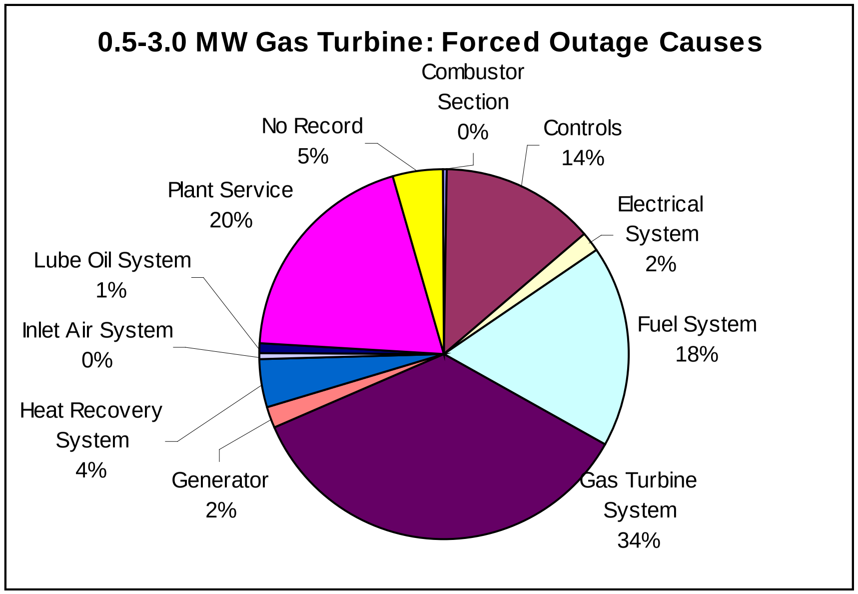
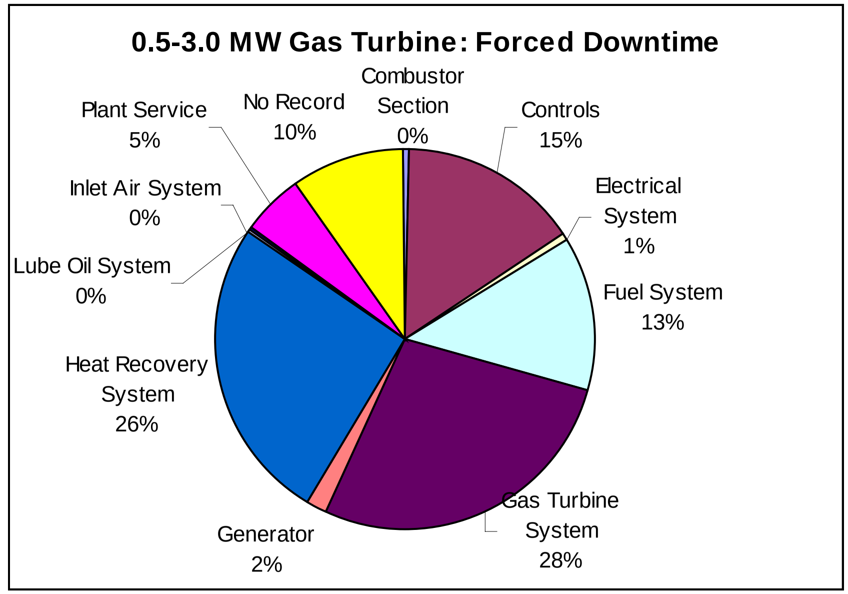


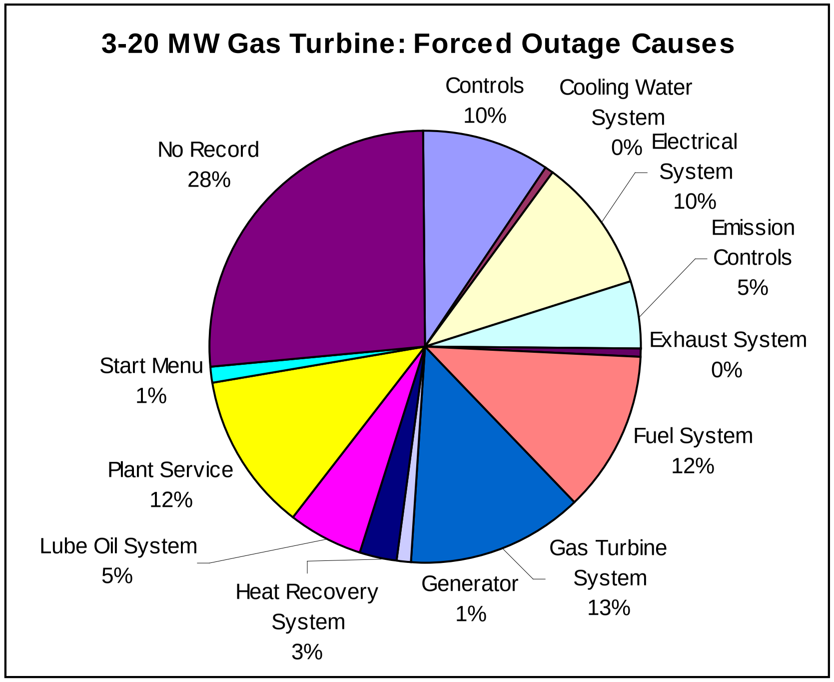
Figure 5.4 - Outage Causes as a Percent of Occurrences and Total Downtime: 0.5-3.0 MW Gas Turbine Systems

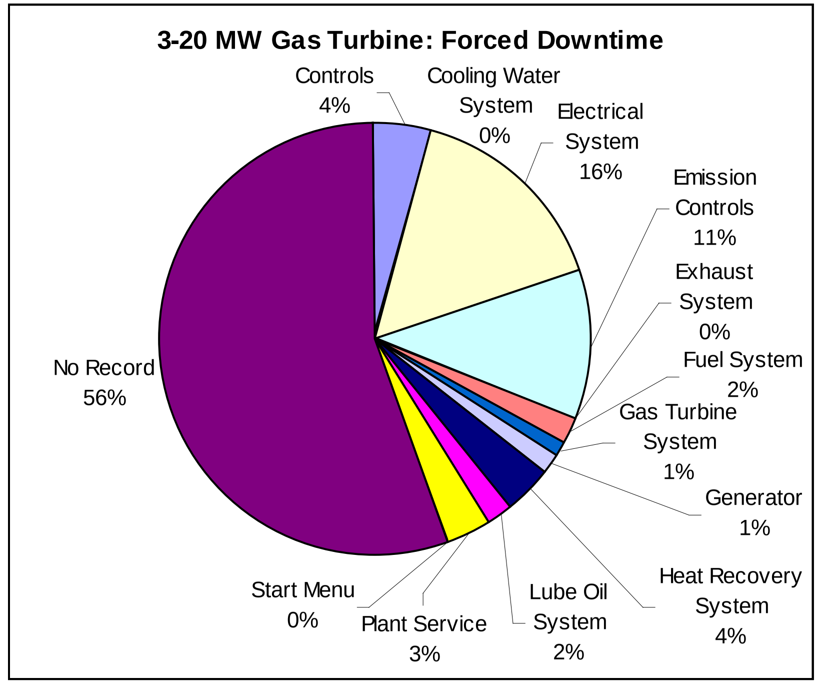




Note that in the case of the 0.5-3.0 MW gas turbine group that two forced outages on a single unit accounted for 1961 hours of forced downtime attributed to Heat Recovery System (extended derate, HRSG inspection, tube leak and repair) or 94% of all downtime due to Heat Recovery System.

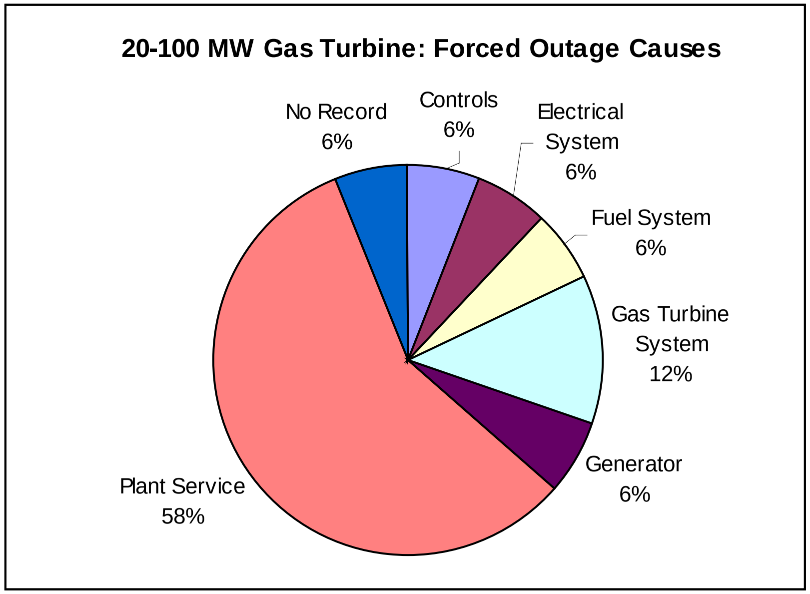
Figure 5.5 - Outage Causes as a Percent of Occurrences and Total Downtime: 3-20 MW Gas Turbine Systems





Note that in the case of the 3-20 MW gas turbine group that a single forced outage on one unit accounted for 155.7 hours of forced downtime attributed to Heat Recovery System or 61% of all downtime due to Heat Recovery System.

Figure 5.6 - Outage Causes as a Percent of Occurrences and Total Downtime: 20-100 MW Gas Turbine Systems



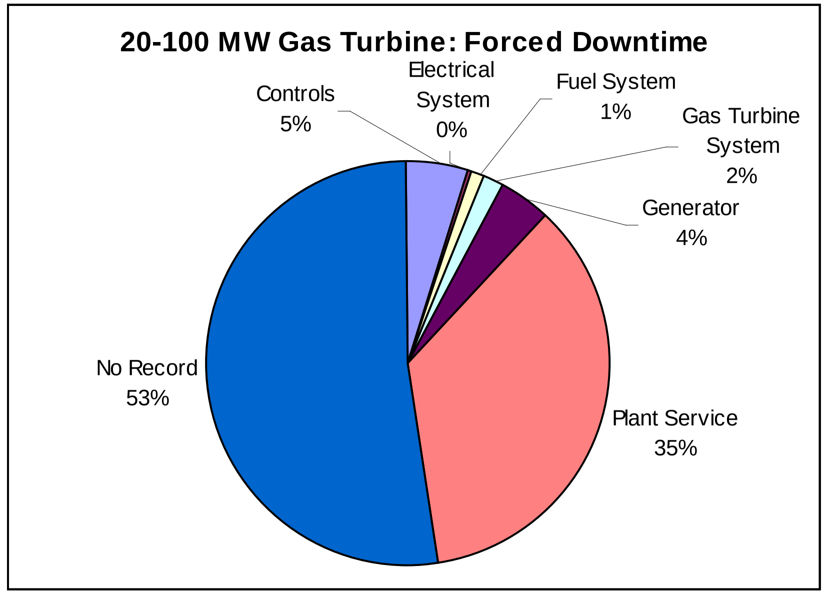
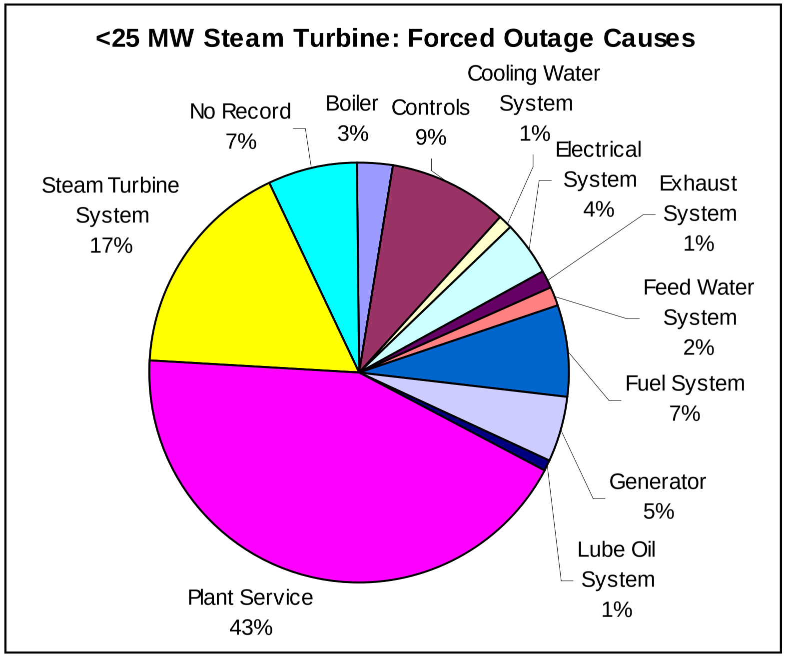
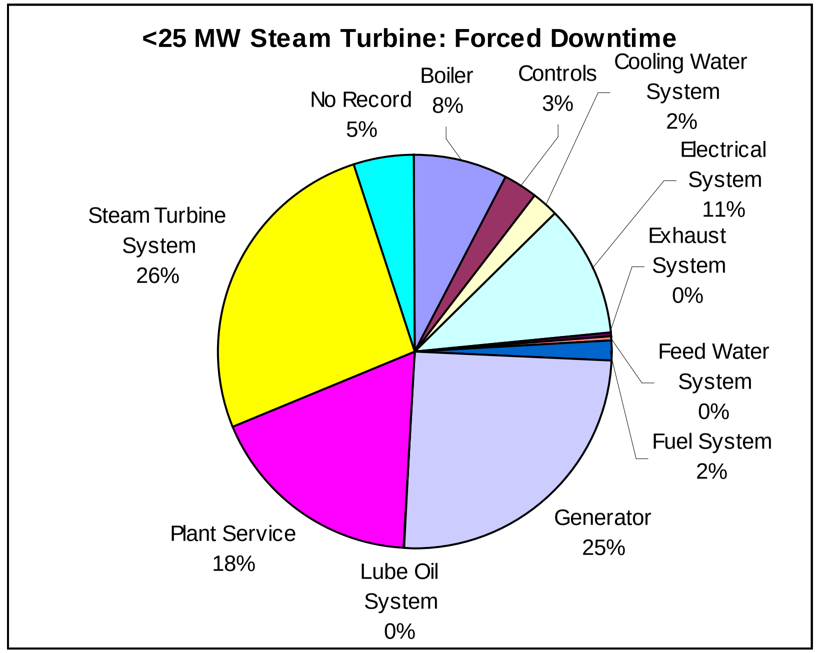


Figure 5.7 - Outage Causes as a Percent of Occurrences and Total Downtime: <25 MW Steam Turbine Systems





6 CONCLUSIONS

6.1 Introduction

Demonstrated acceptable levels of DG/CHP system operational reliability (OR) performance is a critical element in market development. This project represented the first attempt to establish baseline operating and reliability data for DG/CHP systems in more than a decade. The database framework established is a solid foundation for continued data collection and analysis of OR performance of onsite generation technologies.

The entire project methodology was based heavily on the involvement of DG/CHP users. Data (maintenance logs, operation records, and other available sources) and results came directly from actual customer operating data and experience. This required an extremely labor-intensive effort on the part of both project participants and the project team. The voluntary cooperation of participating facilities and time assembling data and being interviewed was greatly appreciated. While time-intensive the involvement of users created better understanding of actual operations.

6.2 Discussion of Results

The DG/CHP units in our database sample demonstrated on average good OR performance. The OR measures calculated were comparable to or better than OR performance of central station technologies. The use of multiple units at sites can undoubtedly result in very-high levels of availability.

During the course of the project, specific units were observed to exhibit both very good to poor OR performance. In almost all technology groups, subsystems other than the prime movers themselves contributed significantly to occurrence of forced outage events. Many events that occur are the result of random equipment failures expected of any complex power system. Other events may be nonrandom in nature, indicating problems that may relate to issues pertaining to the unit design or installation. This project did not result in the identification of any such systemic problems. Most failures within technology groups appear to be random occurrences of short duration.

It is noteworthy that OR performance of established commercial technologies (i.e., reciprocating engines and gas turbines) was significantly better than the sample of emerging technologies (fuel cells) included in the project. Fuel cell operational reliability indices calculated were significantly lower than all other technology groups and what fuel cell manufacturers typically quote. Availability, forced outage rate and mean down time were greatly affected by downtime associated with unusually long delay (e.g., maintenance personnel response, availability of replacement parts, site operations) and not related to typical operation. It would be unfair to attribute downtime to equipment that is more appropriately attributed to the developing nature of the service system. The OR performance of emerging technologies and early commercial products need to be compared separately. Established products have the benefit of millions of hours of operation from which to develop operations and maintenance best practices. Their observed performance in this project and prior work bears this out. As time passes and more experience is gained from the operation of emerging technologies, it is likely their demonstrated OR performance will improve to the level of the other technologies.

With regard to the database itself, it is intended to establish a baseline of OR data on DG/CHP and allow current and potential users to benchmark reliability. The methodology and framework for recording and analyzing data is straight forward, repeatable and consistent with industry standards. It should be noted that the data reviewed for this project is only for the 2000-2002 time period. The database does not include large samples in all technology groups. It is structured to accommodate more units and technology groups in a follow-on effort. Future periodic updating and maintenance on a regular basis will ensure continued usefulness and increase the confidence in the measures calculated.

6.3 Recommended Follow-on Activities

The first version of the DG/CHP Reliability and Availability Database provides a general framework for recording operating data and analyzing OR performance. It provides a solid foundation for future improvements and enhancements. Recommended improvements to the database framework include:

- Adding additional units to improve the robustness of the data
- Annual updating of data to include years of operation beyond the original 2000-2002 period
- Include microturbines with at least two years of operations (not including R&D demonstration) along with fuel cells with similar operating history in a separate database pertaining to emerging DG/CHP technologies
- Conduct starting reliability analysis on very low service factor standby units

Any follow-up effort needs an efficient site identification and data collection process. For example, monthly data submission by site operators with secure web-based data entry system would reduce the labor costs associated with data collection substantially.

7 REFERENCES

1. *Reliability of Natural Gas Cogeneration Systems*, GRI report 93/0020, Gas Research Institute, 1992.

2. *FOREMAN Software User Guide – An Operations and Maintenance Data Manager and Reliability Reporting System*, Gas Research Institute, 1993.

3. *Recommended Practice for Design of Reliable Industrial and Commercial Power Systems*, IEEE Standard 493-1997, Institute of Electrical and Electronics Engineers, 1998

4. *Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity*, ANSI/IEEE Standard 762, Institute of Electrical and Electronics Engineers, 1988

5. *Reliability Survey of 600-1800 kW Diesel and Gas-Turbine Generating Units,* Smith, C.A., Donovan, M.D., Bartos, M.J., IEEE ICPSD 89-02, Institute of Electrical and Electronics Engineers, 1988.

6. *Reliability Measurements for Gas Turbine Warranty Situations*, Ekstrom, T.E., ASME 92-GT-208, American Society of Engineers, 1992.

7. *1997-2001 Generating Availability Report*, North American Reliability Council/Generating Availability Data System, 2002.

APPENDIX A CANDIDATE SOLICITATION LETTER

Dear Developer/Manufacturer/Operator of Distributed Generation Facilities:

On behalf of the U.S. Department of Energy and Oak Ridge National Laboratory, Energy Nexus Group, a subsidiary of ONSITE Energy, is writing to make you aware of a contract recently awarded to us regarding reliability of distributed generation systems and to inquire about your willingness and ability to participate in this worthwhile project.

We hope you find value in participating in this worthwhile project. The project focuses on the development of a specific information tool to help accelerate the development of the industrial Distributed Generation (DG) market: an operational reliability and availability database for on-site generation technologies. We are seeking your assistance in identifying onsite generation sites with at least two years of operating experience to populate the database. The US DOE has identified the need for improved information on industrial DG system reliability and availability as one of several critical elements in fostering the DG market.

The final work product will be a database of operational reliability data for DG systems. The database will allow individual DG facility managers to better understand reliability and availability performance of their particular units and also determine how their facilities compare with other DG resources. Detailed information on DG reliability and availability performance will enable potential DG users to make a more informed purchase decision, and will help policy makers quantify potential grid system benefits of customer-sited DG. For example, the reliability information can be used as an advocacy tool in working with regulators on reasonable standby power rates and backup charges.

The methodology for assessing the operational reliability of DG systems will be to initially establish baseline operating and reliability data for industrial distributed generation systems through an exhaustive collection of data from a representative sample of operating facilities. Information will be gathered from maintenance logs, operation records, manufacturers' data, and other available sources. The project team will then identify and classify DG system failures and outages for various types of technology, fuels and applications. A failure mode analysis will provide insight into system failure modes and causes, and quantify system downtimes for planned and unplanned maintenance.

We are currently in the process of identifying and screening potential sites to populate the database and could use your assistance. In developing our technical approach we recognized that the operational reliability performance data base must address diverse prime mover technologies and applications, the calculated performance statistics must be statistically meaningful, and the procedures for collecting, processing, and analyzing data must be tightly controlled. To that end, we have developed the following general criteria for screening potential sites for inclusion in the database.

- Minimum of two years of operating service
- Completeness of O&M data
- Willingness to allow the project team to review O&M data
- Representative of the technology and prime mover population as a whole
- O&M Practice (e.g., in-house or contracted maintenance, continuous or cycling)
- Geography
- Customer sector

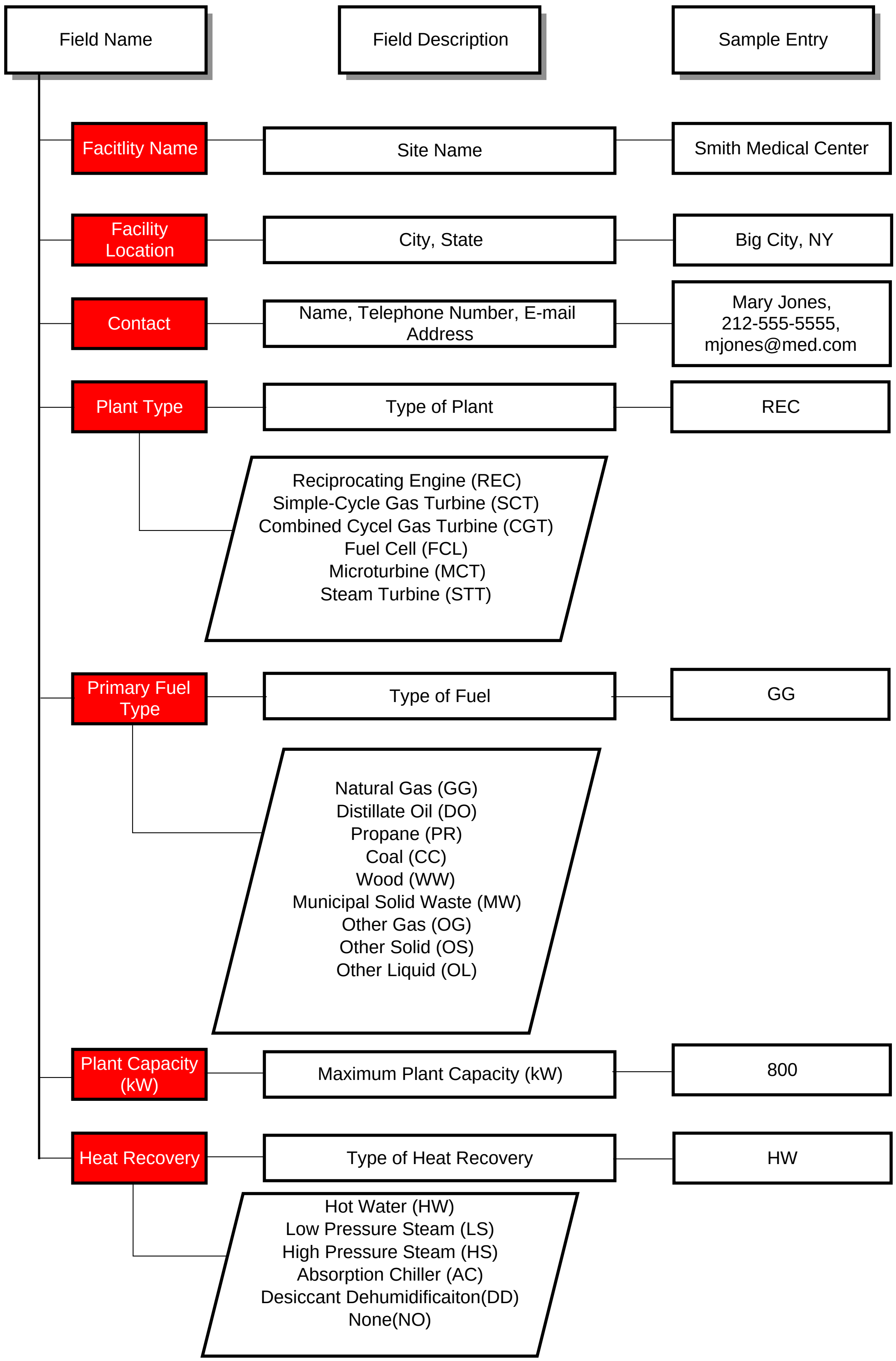
Again, it is envisioned that the final work product of this project will allow for better understanding of reliability and availability performance of particular DG technologies and determine how facilities compare with other DG resources. The results will also allow for improved financial analyses to be conducted with better understanding of operational and financial impacts of unavailability, likely unplanned outages, and other service interruptions.

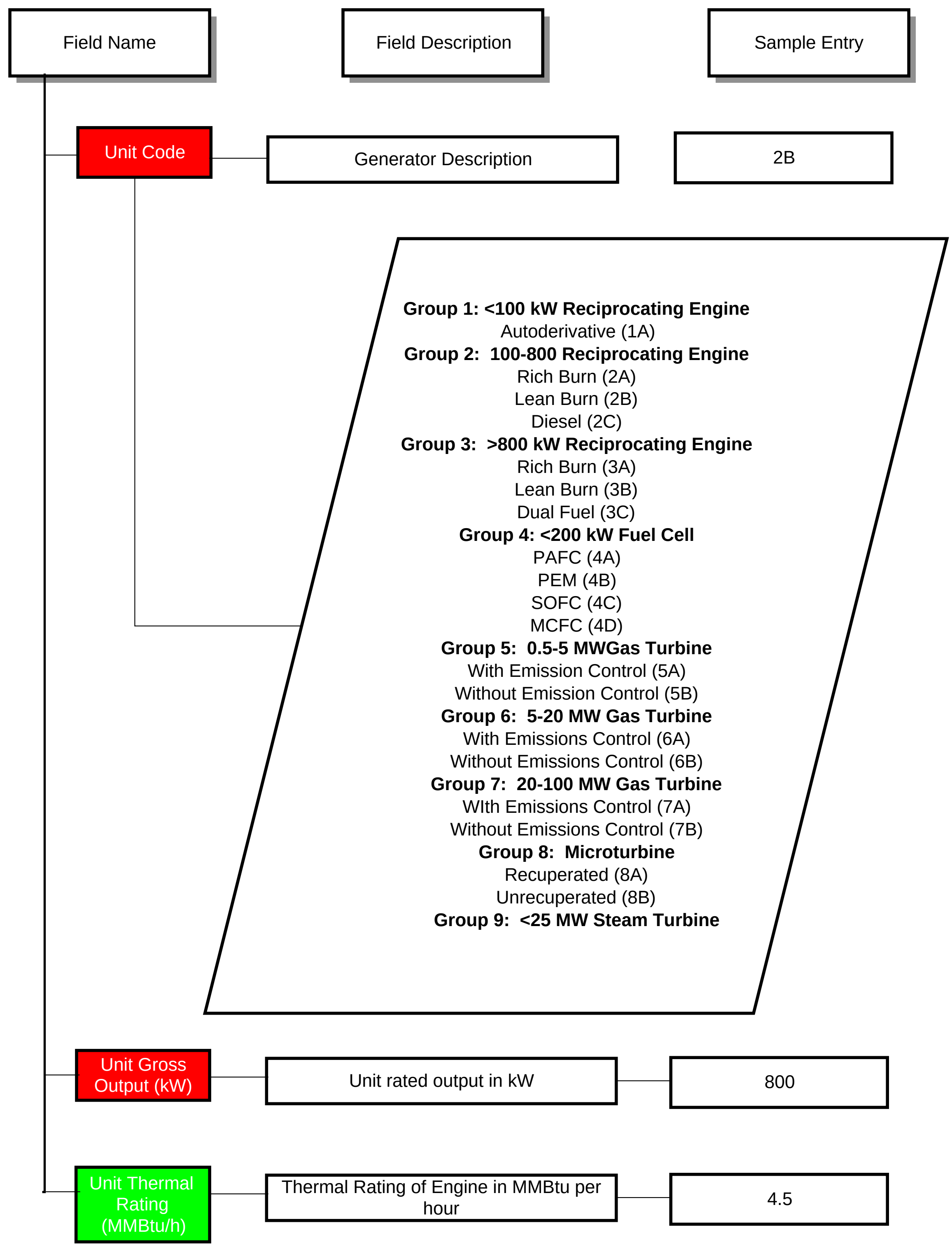
If you have sites in mind that would be good candidates for inclusion in the database please contact me. In the meantime, you may be contacted by a member of the project team regarding your participation and with a more detailed set of questions regarding participating and the screening criteria for inclusion in the final database.

Thank you for your time and consideration.

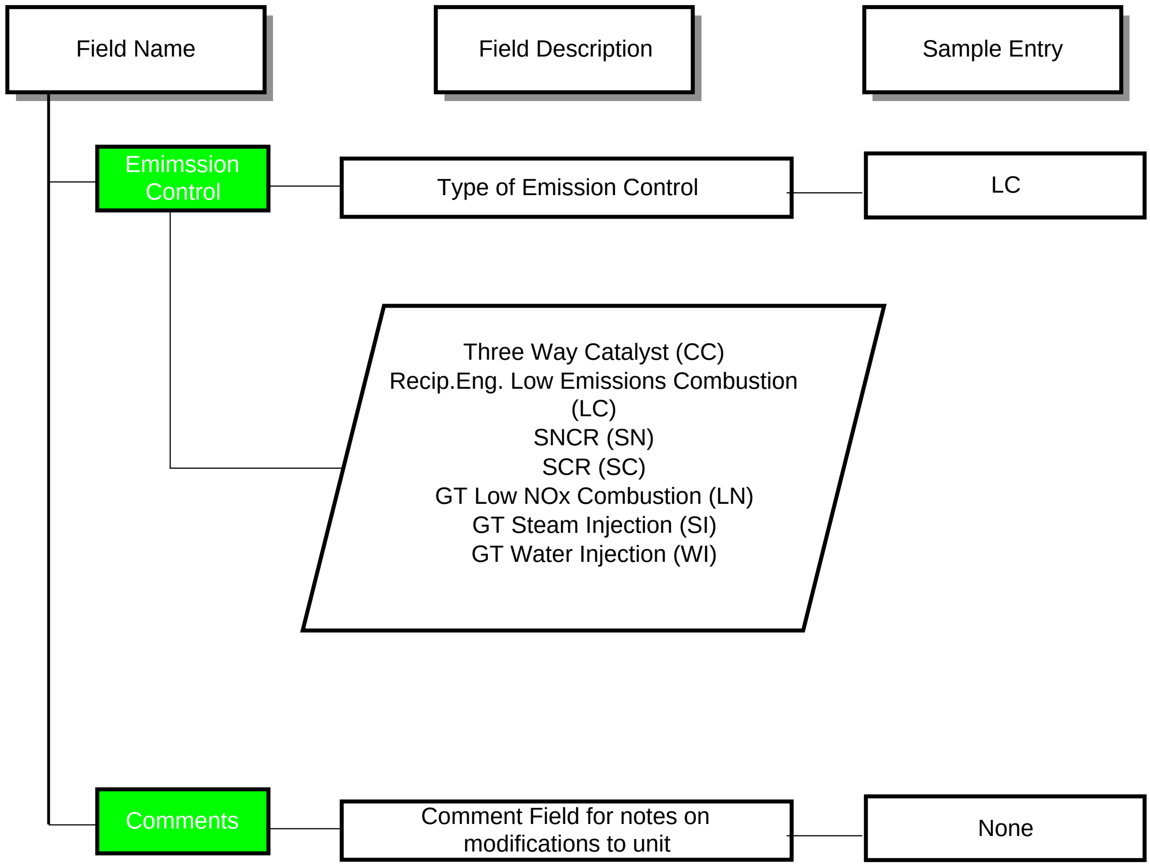
APPENDIX B DATA COLLECTION AND MANAGEMENT SOFTWARE STRUCTURE AND USER GUIDE

Facility/Plant Information




Field Name
Field Description
Sample Entry
Unit Code
Generator Description
2B
Group 1: <100 kW Reciprocating Engine
Autoderivative (1A)
Group 2: 100-800 Reciprocating Engine
Rich Burn (2A)
Lean Burn (2B)
Diesel (2C)
Group 3: >800 kW Reciprocating Engine
Rich Burn (3A)
Lean Burn (3B)
Dual Fuel (3C)
Group 4: <200 kW Fuel Cell
PAFC (4A)
PEM (4B)
SOFC (4C)
MCFC (4D)
Group 5: 0.5-5 MWGas Turbine
With Emission Control (5A)
Without Emission Control (5B)
Group 6: 5-20 MW Gas Turbine
With Emissions Control (6A)
Without Emissions Control (6B)
Group 7: 20-100 MW Gas Turbine
WIth Emissions Control (7A)
Without Emissions Control (7B)
Group 8: Microturbine
Recuperated (8A)
Unrecuperated (8B)
Group 9: <25 MW Steam Turbine
Unit Gross Output (kW)
Unit rated output in kW
800
Unit Thermal Rating (MMBtu/h)
Thermal Rating of Engine in MMBtu per hour
4.5

Unit Information continued (needed for each unit at facility)

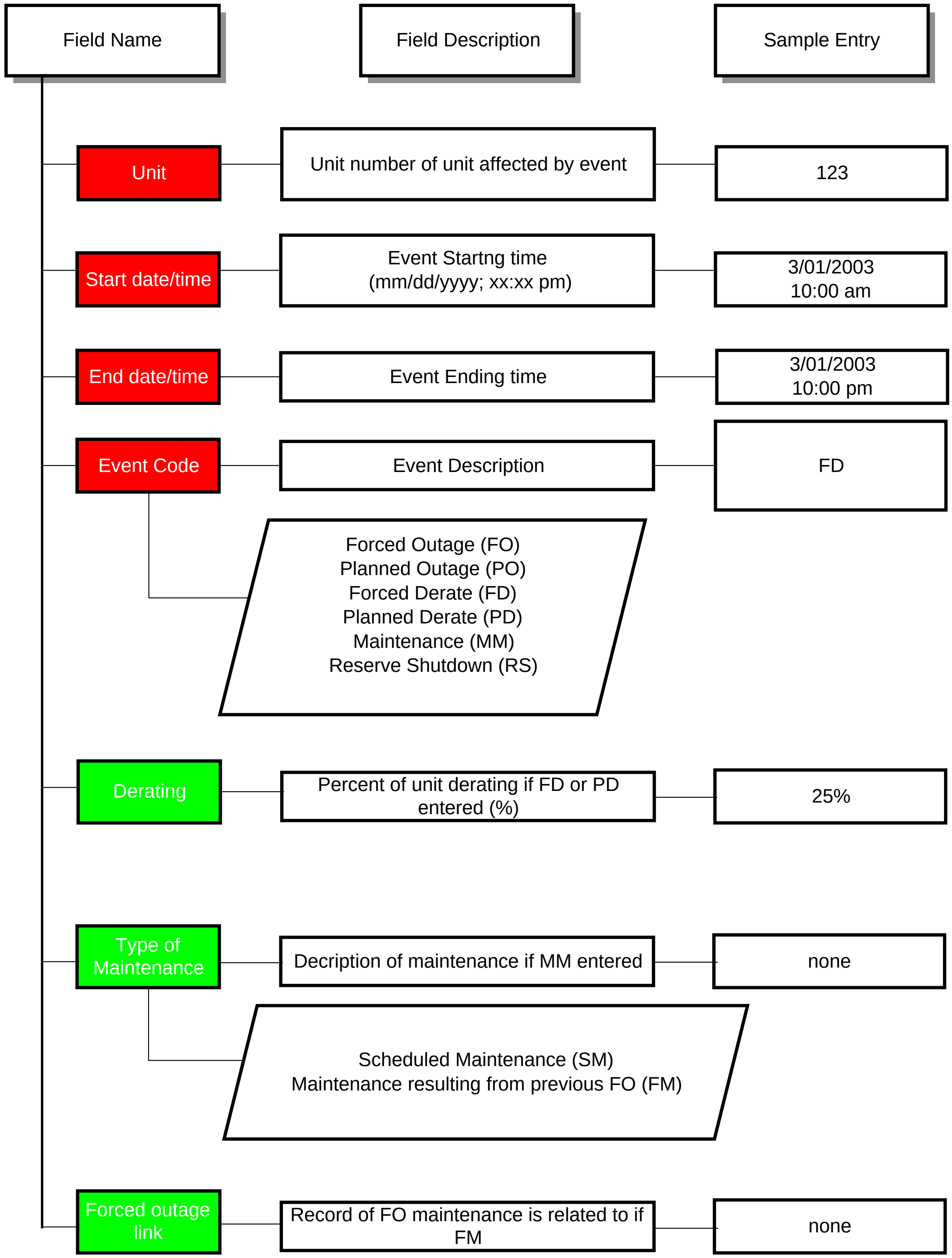


A unique record number for each facility and unit will be assigned

Monthly Generation History (needed for each unit)

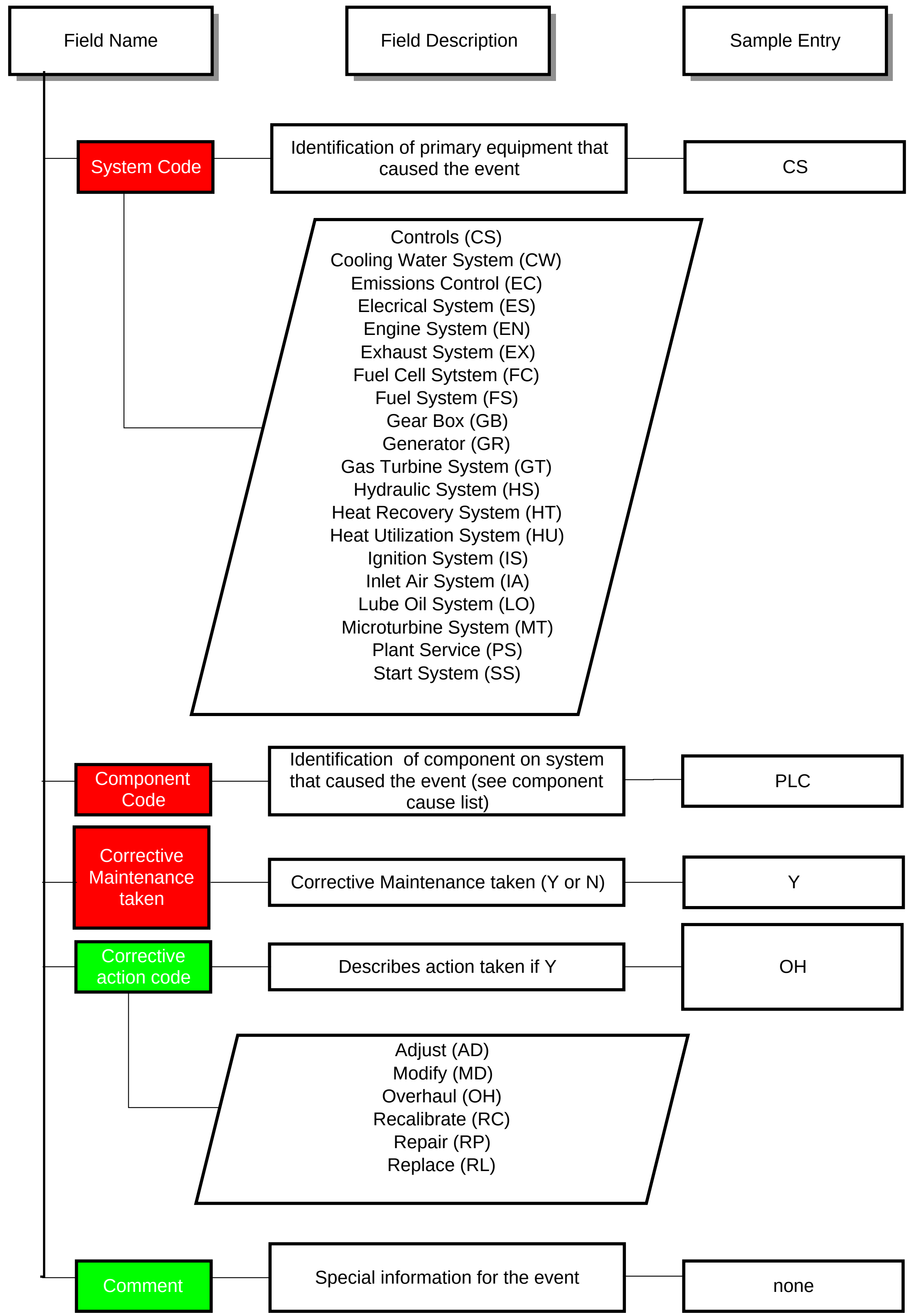
Field Name	Field Description	Sample Entry
Unit Record Number	Unique number assigned to each unit	123
Month	Date (MM/YYYY)	10/2003
Total Service Hours	Total run hours at any output (hrs)	700
Number of Attmepted Starts	Number of starts attempted to bring the unit from shutdown to synchronizations. Repeated failure to start for the same cause without a corrective action is considered a single attempt.	4
Number of Successful Starts	Number of times the unit successfully started and sychronized	3

Event Log Data



Each event for every unit will be assigned an event record number (e.g., 1,2,3...)

Event Log Data continued



Component Cause List

Controls
Microprocessor
Data Logger
Modem
Power Supply
Overspeed Board
Control Cards
Relay Input Board
Governor Board
Analog Temp Board
Distributed Control System (DCS)
Panel Devices
Software Error
Programmable Logic Controller
Multiplexer
Local Area Network
I/O Module
Slave Module
Termination Unit
Unknown Trip

Cooling Water System
Pump
Radiator
Coolant
Belt
Transducer
Radiator Cap
Hose
Flow Switch
Piping
Pressure Switch
Gauges

Emissions Control
Catalyst
Piping/Ductwork
Water Injection System
Steam Injection System
SCR System
Engine LEC
GT LNC
SNCR
Instrumentation/Controls
Compliance Testing

Electrical System
Instrumentation
Battery
Governor
Circuit Breaker
Power Supply
Wires/Fuses
Stepper Motor
Meters
Distribution
Battery Cable
Relay
Main Fuse

Engine System
Heads
Valve Train
Timing Gear
Crankshaft
Pistons
Connecting Rods
Inlet Manifold
Bearings
Cylinders
Flywheel
Camshaft
Gaskets
Engine Block
Freeze Plugs
Ring Gear
Vibration Switch
Rings
Turbocharger
Aftercooler
Temperature Switch
Gauges
Pressure Switch
Engine Overhaul

Exhaust System
Silencer
Piping
Gaskets
Exhaust Heat Exchanger
Instrumentation/Wiring
Ducting

Fuel Cell System
Fuel Processor
Fuel Quality Monitor
Reformer Inspection
Planned Stack Replacement
Stack Inspection
Stack Temperature Monitor
Fire Detection
Voltage Decay Monitor
Vibration Monitor
Power Electronics
Inverter
Utility Interface
Instrumentation/Wiring
Planned Overhaul

Fuel System
Pressure Regulator
Carburetor
Piping and Valves
Separator
Gas Pump
Prechamber Valves
Fuel Injectors
Fuel Nozzles
Instrumentation/Wiring

Gear Box
Gear Train

Cooler
Oil System
Accessory Drive

Generator
Induction Generator
Bearings
Couplings
Synchronous Generator
Cooling System
Contactor
Instrumentation/Wiring
Excitator
Overhaul

Gas Turbine System
Compressor Section
Combustor Section
Turbine Section
Exhaust Section
Couplings or Clutches
Water Washing
Combustor Inspection
Turbine Section Inspection
Main Bearings
Fuel Nozzle
Transition Pieces
Combustor Seals
Inlet Guide Vanes
Turbine Sealing
Fire Detection System
Inlet Air System
Vibration Monitor
Temperature Monitor
Instrumentation/Wiring
Overhaul

Hydraulic System
Pumps
Piping and Valves
Instrumentation/Wiring
Heat Exchanger
Temperature Regulator

Heat Recovery System
Engine Coolant Heat Exchanger
Pumps and Piping
Pressure Relief Valve
Pressure Regulator Valve
Electronic Controls
Instrumentation/Wiring
Hot Water Heat Recovery Unit
Low Pressure Steam Heat Recovery Unit
High Pressure Steam Heat Recovery Unit
Expansion Tank
Cleaning
Economizer
Superheater
Evaporator
Steam Drum
Structures
Electronic Controls

Duct Burner
Dampers/Duct Work
Inspections/Cleaning
Feedwater System
Boiler Feed Pump
Dearator
Valves/Piping
Instrumentation/Wiring
Sootblower

Heat Utilization System
Steam Condenser
Absorption Chiller
Cooling Tower
Valves
Pumps
Instrumentation/Wiring
Vents
Piping
Steam Turbine

Ignition System
Wiring
Spark Plugs
Distributor
Coil
Ignitor

Inlet Air System
Filter
Fan Bearing
Fan Belt
Fan Motor
Fan Shaft
Silencer
Hose
Ductwork
Guidevanes

Lube Oil System
Filter
Oil Add or Change
Pressure Control
Pump
Cooler
Temperature Regulator
Pressure Regulator
Instrumentation
Wiring
Sump
Piping/Seals
Precipitator

Microturbine System
Controls
Heat Exchanger
Recuperator
Bearing
Gas Compressor
Vibration Monitor
Fuel Nozzle
Dampers/Ducting

Turbomachinery

Plant Service
Gas Utility
Electric Utility
Host Facility

Start System
Electric Starter
Battery
Power Supply
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Piping

DG Reliability Survey Tool

User Guide

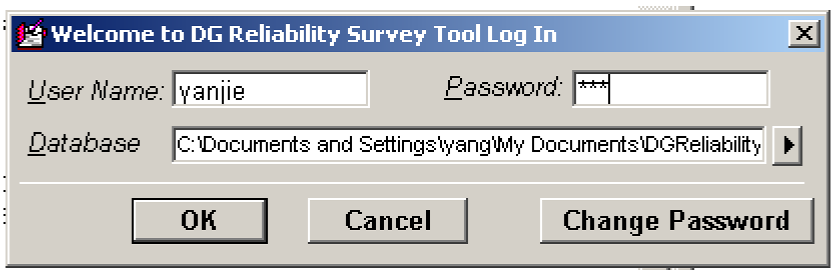
Version 1.0

March 2002

By

Gas Technology Institute
1700 South Mount Prospect Road
Des Plaines, IL 60018

Log-in Interface



The user Log-in form is designed to provide the DG Reliability Survey Tool (DGRST) database security and protect from unauthorized database modification/entries.

<u>Login Commands</u>

Ok command

Use **OK** command to log in the DGRST application after password validation.

Cancel command

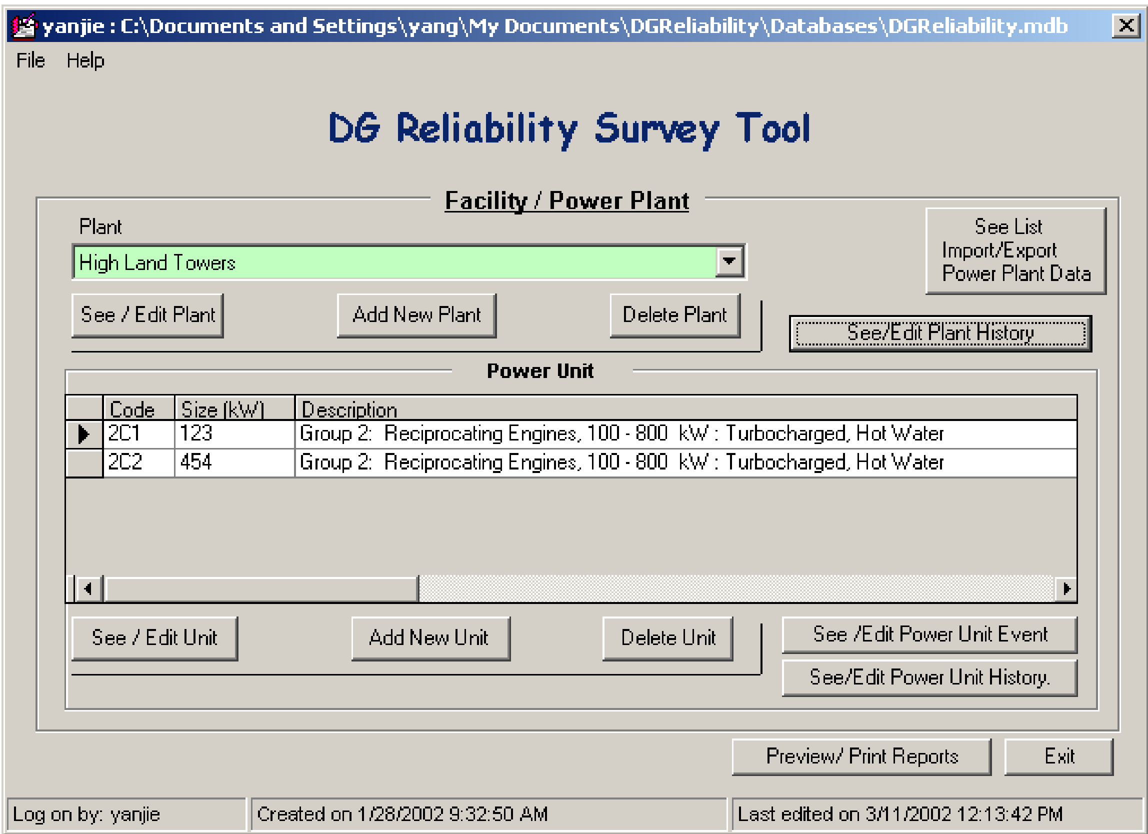
Use **Cancel** command to quit the DGRST application.

Change Password command

Use **Change Password** command to change current user's password after logging in the DGRST application with password validation

DG Reliability Survey Tool (DGRST)

The Main interface provides users with options to select, review, edit, add, delete, import and export plant specific segment of DGRST database.



File Menu

Open command (File menu)

Use the **Open** command to open a new Database Back-end.

Exit command (File menu)

Use the **Exit** command to exit the DGRST application.

Help Menu

Contents command (Help menu)

Use the **Contents** command to call up the DG Reliability Survey Tool Online Help Index. Using this index as a starting point, you can quickly find any Help topic of interest. Once in online Help, you can always return to the main window by clicking the Contents button in the upper left corner of the Help window.

About command (Help menu)

Use the **About** command to find the version number and other pertinent information about DG Reliability Survey Tool.

See / Edit Plant command

Use the **See / Edit Plant** command to be prompted to review or edit the related general information for Facility/plant on the form of **Error! Bookmark not defined.**

Add New Plant command

Use the **Add New Plant** command if you need to add a new facility / plant name. When you choose the Add New Plant command, you will be prompted to specify a new Facility name and location and the related general information on the form of **Error! Bookmark not defined.**

.

Deleted Plant command

Use **Delete Plant** command if you need to delete the facility /plant from the DGRST database**.** **Warning**: once completion of the command, all the facility related information on units, events, and history data will be deleted and can not be undone.

See/Edit Plant History command

Use the **See/Edit Plant History** command to be prompted to review all the plant Monthly History Data on the form of **Error! Bookmark not defined.**

See List /Import/Export Power Plant command

Use the **See List /Import/Export Power Plant** command to be prompted to review the list of all plants in the DGRST database on the form of **Error! Bookmark not defined.**.

See / Edit Unit command

Use the **See / Edit Unit** command to be prompted to review or edit the related general information for the unit on the form of **Error! Bookmark not defined.** One unit should be highlighted from the unit list before clicking on the command.

Add New Unit command

Use the **Add New Unit** command if you need to add a new facility / plant name. When you choose the Add New Unit command, you will be prompted to specify a new unit description and the related information on the form of **Error! Bookmark not defined.**.

.

Deleted Unit command

Use **Delete Unit** command if you need to delete the unit from the DGRST database**.** One unit should be highlighted from the unit list before clicking on the command. **Warning**: once completion of the command, all the unit related information on events and history data will be deleted and can not be undone.

See / Edit Power Unit History command

Use the **See / Edit Power Unit History** command to be prompted to review all the Unit Monthly History Data on the form of **Error! Bookmark not defined.** One unit should be highlighted from the unit list before clicking on the command.

See / Edit Power Unit Event command

Use the **See / Edit Power Unit Event** command to be prompted to review all the events for the unit on the form of **Error! Bookmark not defined.** One unit should be highlighted from the unit list before clicking on the command.

Preview/Print Reports command

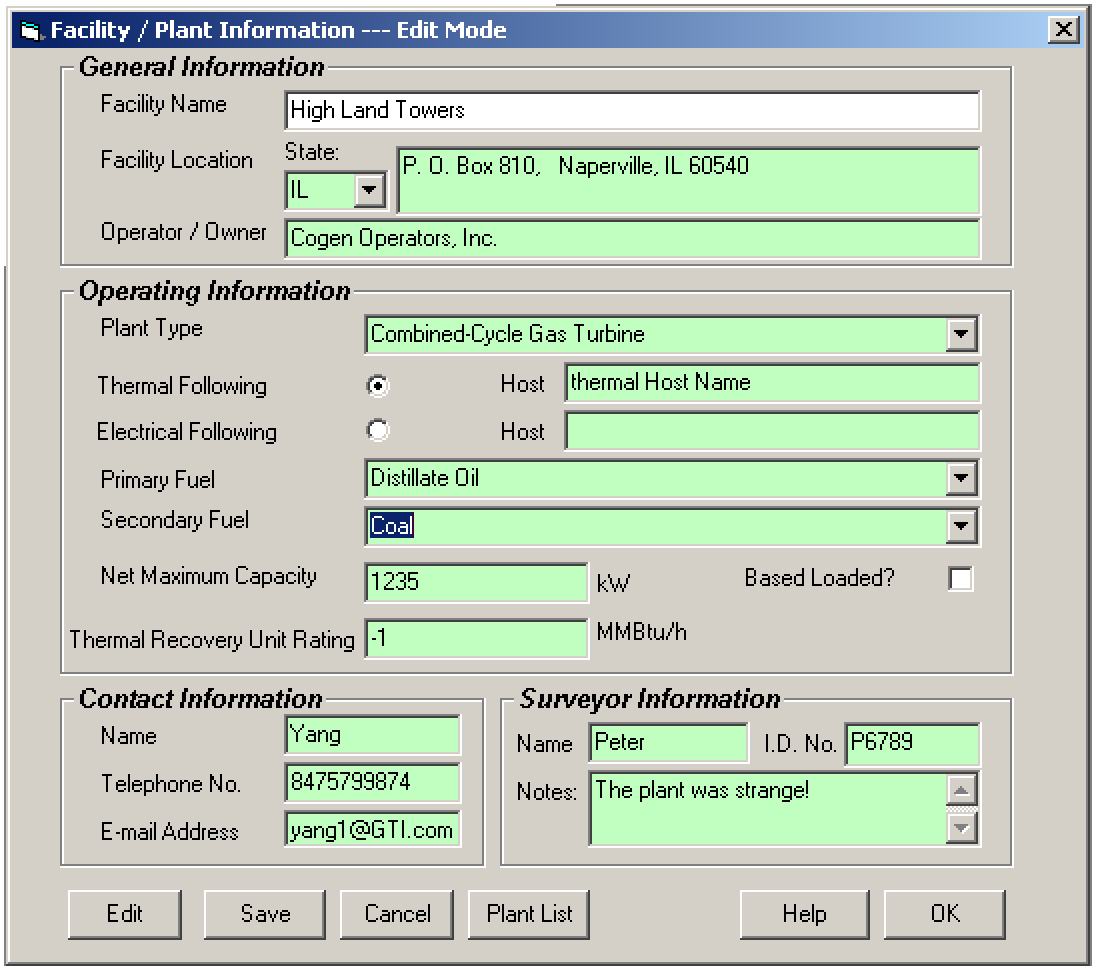
Use the **Preview / Print Reports** command to be prompted to specify reports which you need to preview/print on the form of **Error! Bookmark not defined.**. Plant and /or Unit should be selected before clicking on the command.

Exit command

Use the **Exit** command to exit the DGRST application. It has the same functionality as the Exit command on the File menu.

Facility / Plant Information

Once the plant is selected, related general information can be reviewed / edited. This screen also provides fields to enter contact person and surveyor information.



<u>Facility / Plant Information Commands</u>

Edit command

Use **Edit** command to change the form into the editable mode. The data in the box with light green color can be edited directly. After Edit command executing, Save command will be enabled for saving the update data, and Close command will change to OK command for saving the update data and closing the form.

Save command

Use **Save** command to save all the data on the form. After Save command executing, the form change back to un-editable mode. The back color in data boxes will be light yellow, which means non-editable and only for display. The form changes back as the initial status, non-editable.

Cancel command

Use **Cancel** command to close the form, without saving any update data.

Plant List command

Use **Plant List** command to be prompted to review the list of all plants in the DGRST database on the form of **Error! Bookmark not defined.**

Help command

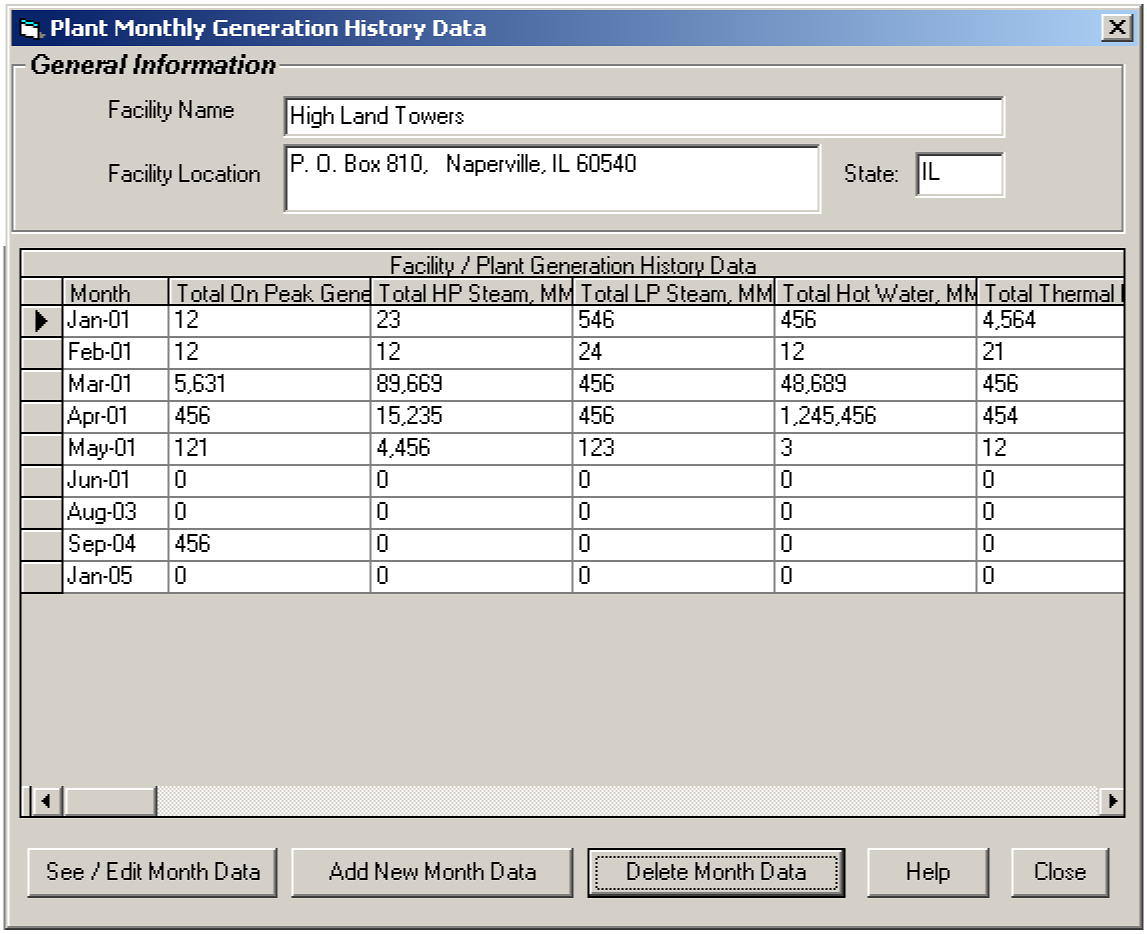
Use **Help** command to show the on-line help information for this form.

Close (OK) command

Use **Close (OK)** command to close the form, without (with) saving the update data.

Plant Monthly Generation History Data

Plant Monthly Generation History Data form is used to show all the monthly data for the plant. Also, it provides users options to review, edit, add and delete monthly data.



Plant Monthly Generation History Data

General Information

Facility Name: High Land Towers

Facility Location: P. O. Box 810, Naperville, IL 60540 State: IL

Facility / Plant Generation History Data

Month	Total On Peak Gene	Total HP Steam, MM	Total LP Steam, MM	Total Hot Water, MM	Total Thermal I
Jan-01	12	23	546	456	4,564
Feb-01	12	12	24	12	21
Mar-01	5,631	89,669	456	48,689	456
Apr-01	456	15,235	456	1,245,456	454
May-01	121	4,456	123	3	12
Jun-01	0	0	0	0	0
Aug-03	0	0	0	0	0
Sep-04	456	0	0	0	0
Jan-05	0	0	0	0	0

See / Edit Month Data | Add New Month Data | Delete Month Data | Help | Close

<u>**Plant Monthly Generation History Data Commands**</u>

See / Edit Month Data command

Use the **See / Edit Month Data** command to be prompted to review or edit the related general information for the Plant on the form of Plant Month Data. One specific month should be highlighted from the month list before clicking on the command.

Add New Month Data command

Use the **Add New Month Data** command if you need to add a new Month Data for the plant. When you choose the Add New Month Data command, you will be prompted to specify a new Month / Year and the related information on the form of **Error! Bookmark not defined.**

.

Deleted Month Data command

Use **Delete Month Data** command if you need to delete the month Data for the plant from the DGRST database**.** One specific month should be highlighted from the month list before clicking on the command. **Warning**: once completion of the command, all the month data will be deleted and cannot be undone.

Help command

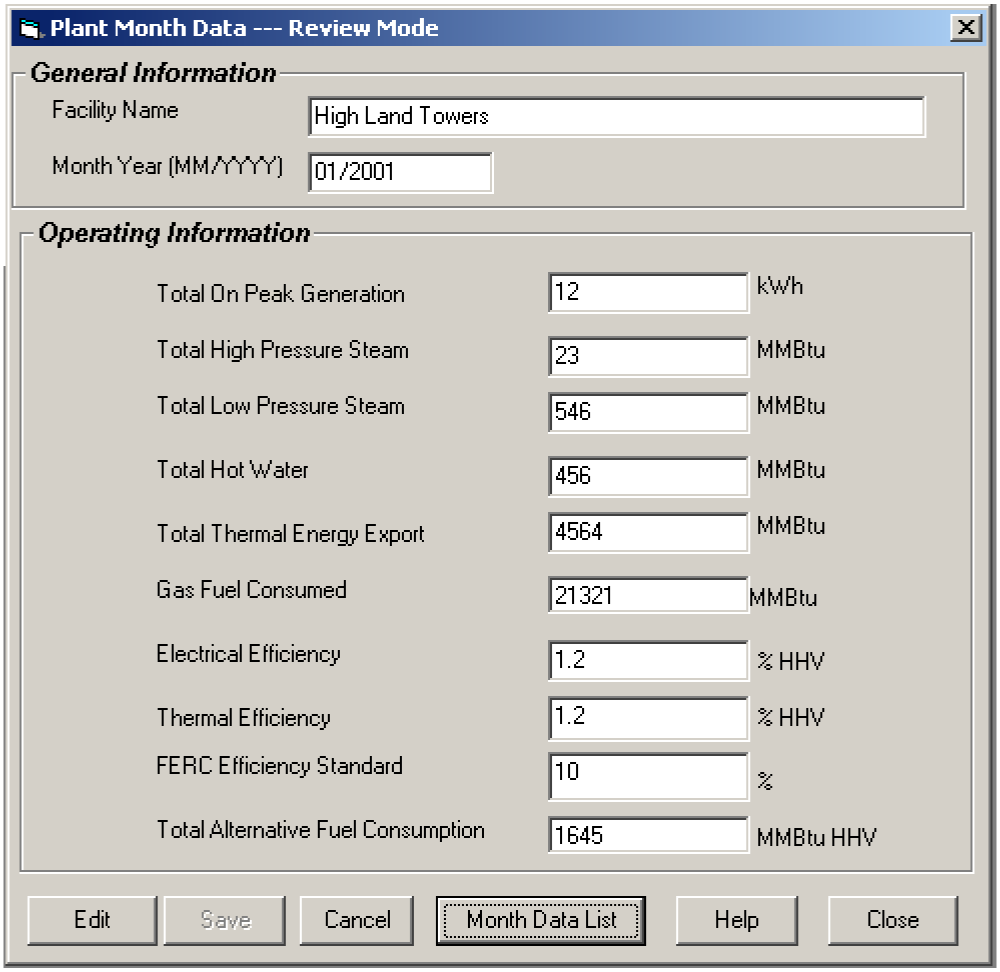
Use **Help** command to show the on-line help information for this form.

Close command

Use **Close** command to close the form.

Plant Month Data

Plant monthly history data can be edited, reviewed on this form.



<u>**Plant Month Data Commands**</u>

Edit command

Use **Edit** command to change the form into the editable mode. The data in the box with light green color can be edited directly. After Edit command executing, Save command will be enabled for saving the update data, and Close command will change to OK command for saving the update data and closing the form.

Save command

Use **Save** command to save all the data on the form. After Save command executing, the form change back to un-editable mode. The back color in data boxes will be light yellow, which means non-editable and only for display. The form changes back as the initial status, non-editable.

Cancel command

Use **Cancel** command to close the form, without saving any update data.

Month Data List command

Use the **Month Data List** command to be prompted to review the data of all the plant monthly generation history data on the form of **Error! Bookmark not defined.**

Help command

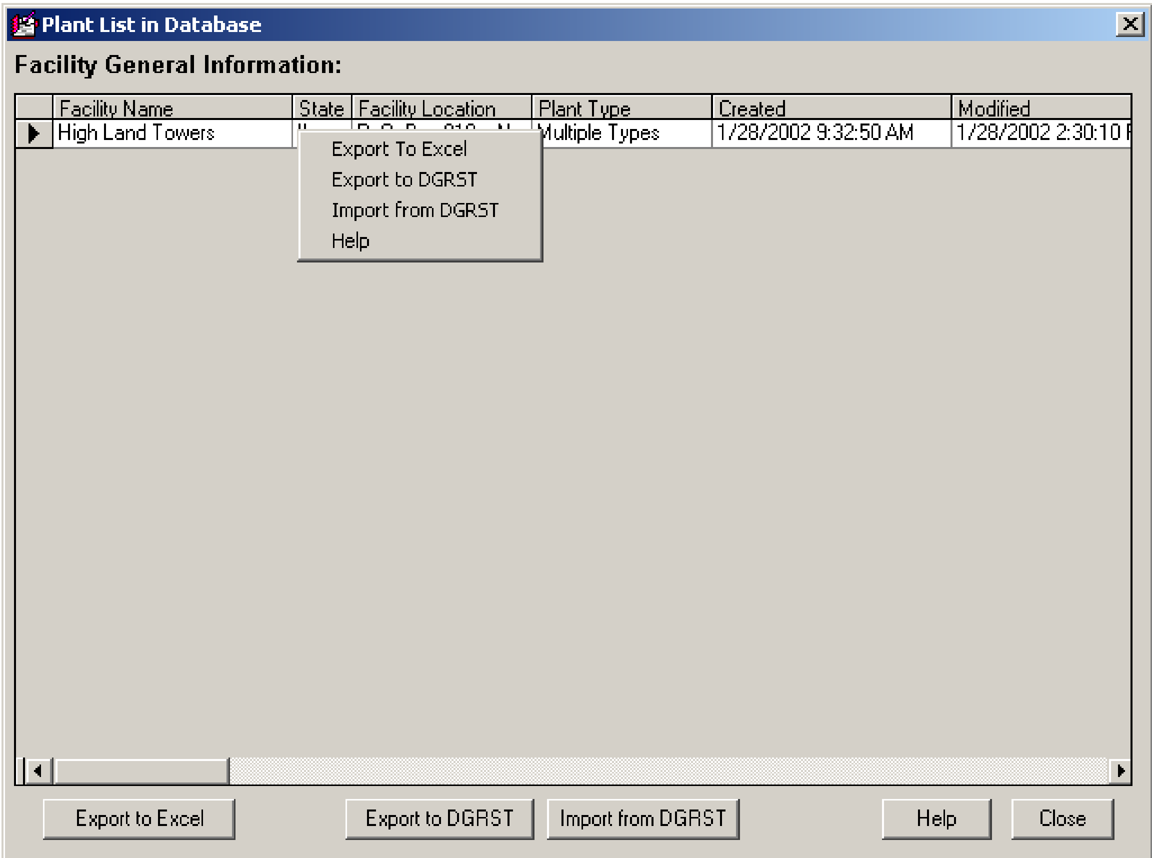
Use **Help** command to show the on-line help information for this form.

Close (OK) command

Use **Close (OK)** command to close the form, without (with) saving the update data.

Plant List in Database

Plant List interface allows user to manipulate sub-sections of the DGRST database by sending/exchanging it in a compact format that can easily be e-mailed.



Plant List in Database Commands

Export to Excel command

Use the **Export to Excel** command if you need to export the data of specific plant(s) to excel spreadsheet. All the information including Plant, Unit Event, Plant History Date, and Unit History Data cam be exported to either a new excel file or an existing excel file.

Export to DGRST command

Use the **Export to DGRST** command to allow users export the information collected using DG Reliability Survey Tool (DGRST) in a very compact format. In this way a full set of collected information associated with a specific plant can be conveniently sent/e-mailed to main location and appended to the main DGRST database (if preferred, a full DGRST database can be send as well).

Import from DGRST command

Use the **Import from DGRST** command to allow users import the information with DGRST format. All the information including Plant, Unit Event, Plant History Date, and Unit History Data in format of DGRST will be imported to the DGRST database directly.

Help command

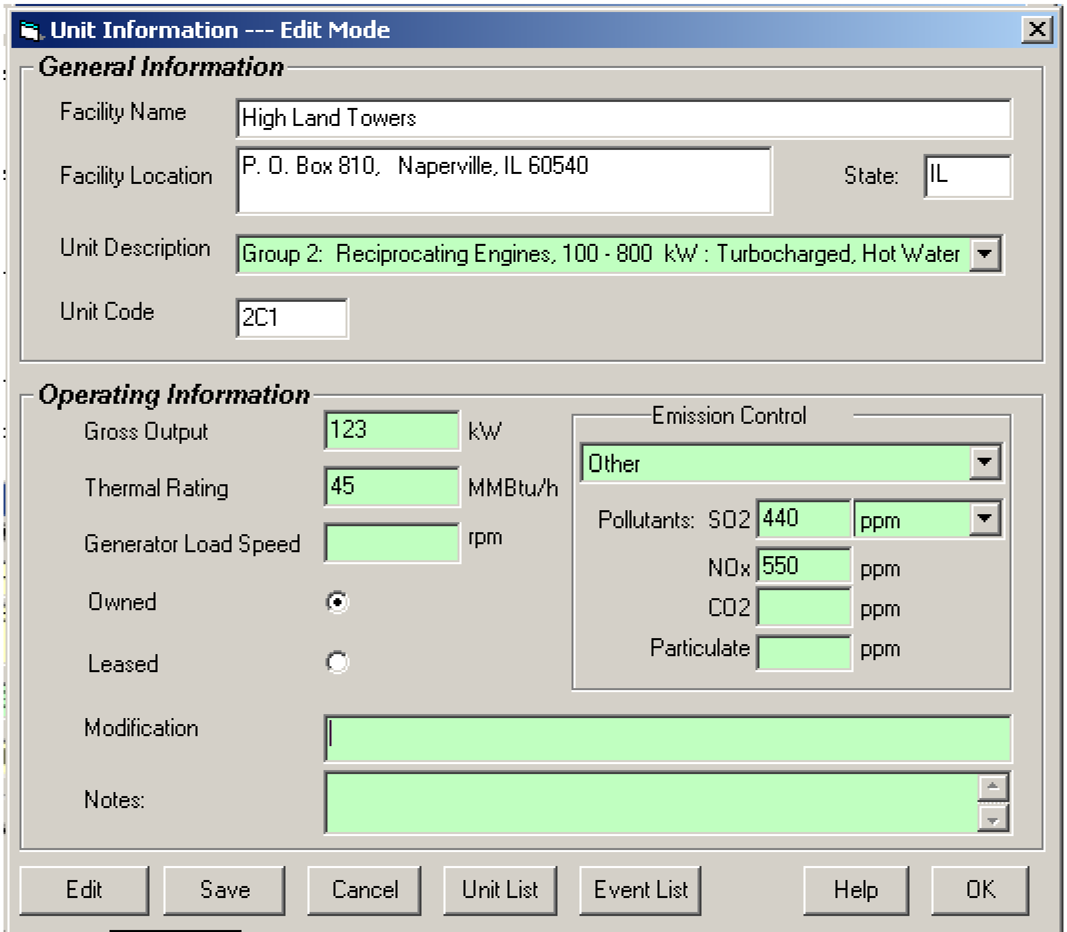
Use the **Help** command to show the on-line help information for this form.

Close command

Use the **Close** command to close the form.

Unit Information

Unit Information can be edited on this form



<u>**Unit Information Commands**</u>

Edit command

Use **Edit** command to change the form into the editable mode. The data in the box with light green color can be edited directly. After Edit command executing, Save command will be enabled for saving the update data, and Close command will change to OK command for saving the update data and closing the form.

Save command

Use **Save** command to save all the data on the form. After Save command executing, the form change back to un-editable mode. The back color in data boxes will be light yellow, which means non-editable and only for display. The form changes back as the initial status, non-editable.

Cancel command

Use **Cancel** command to close the form, without saving any update data.

Unit List command

Use the **Unit List** command to be prompted to review the list of all units for the plant on the form of **Error! Bookmark not defined.**

Event List command

Use the **Event List** command to be prompted to review all the events for the unit on the form of **Error! Bookmark not defined.**

Help command

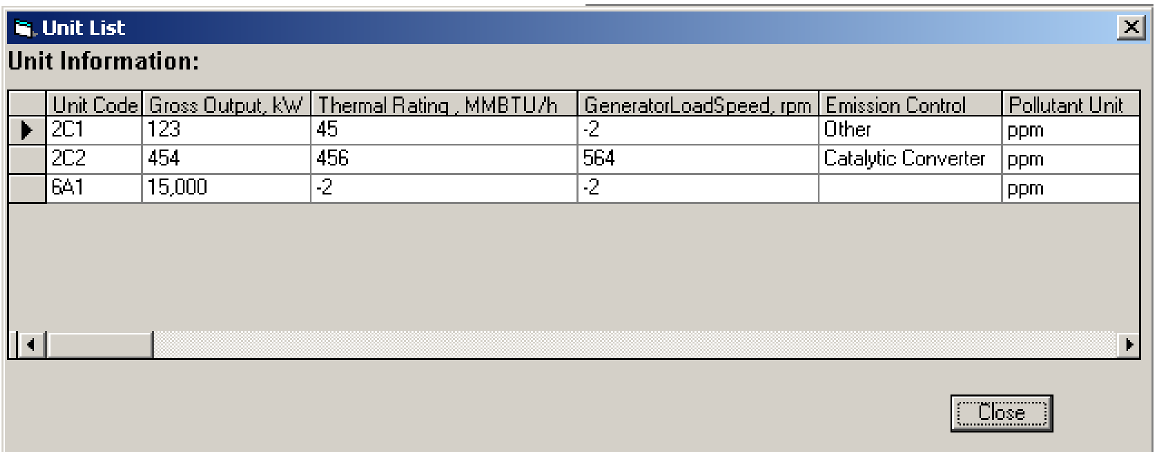
Use **Help** command to show the on-line help information for this form.

Close (OK) command

Use **Close (OK)** command to close the form, without (with) saving the update data.

Unit List

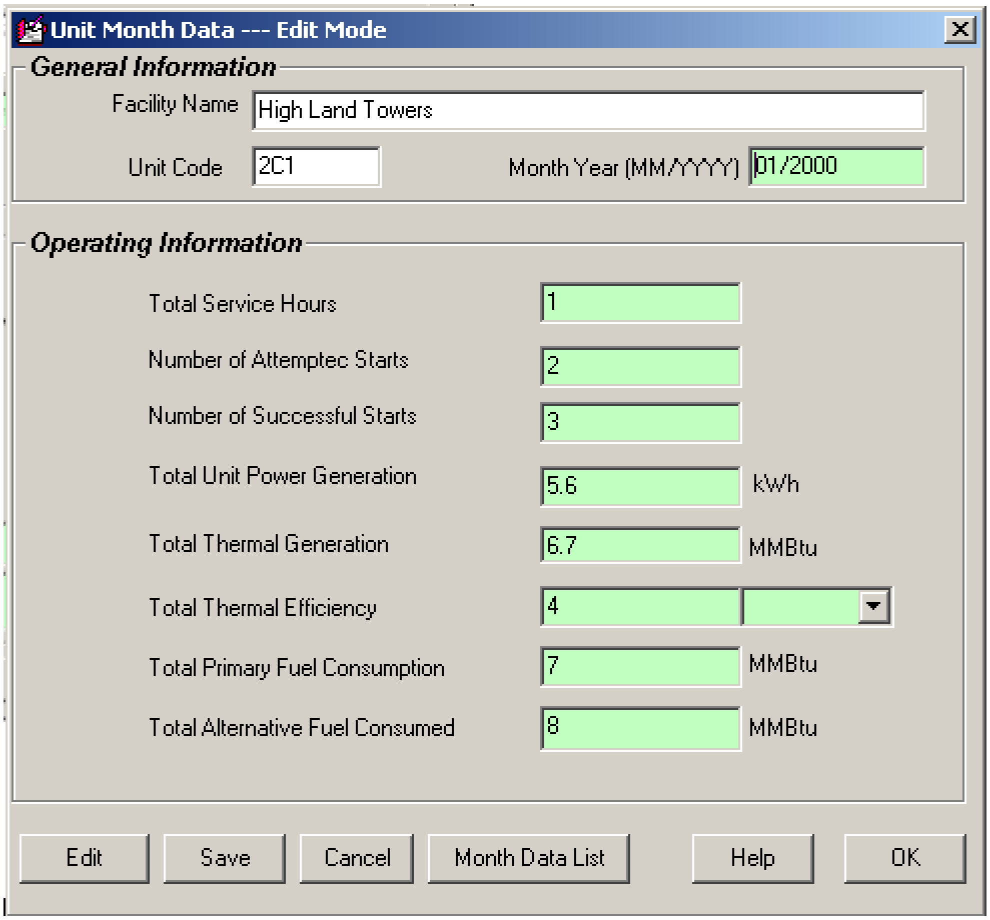
Unit List Interface is used to show the data of all units in the plant.



Unit Code	Gross Output, kW	Thermal Rating , MMBTU/h	GeneratorLoadSpeed, rpm	Emission Control	Pollutant Unit
2C1	123	45	-2	Other	ppm
2C2	454	456	564	Catalytic Converter	ppm
6A1	15,000	-2	-2		ppm

Unit Month Data

Unit monthly history data can be edited, reviewed on this form.



<u>**Unit Month Data Commands**</u>

Edit command

Use **Edit** command to change the form into the editable mode. The data in the box with light green color can be edited directly. After Edit command executing, Save command will be enabled for saving the update data, and Close command will change to OK command for saving the update data and closing the form.

Save command

Use **Save** command to save all the data on the form. After Save command executing, the form change back to un-editable mode. The back color in data boxes will be light yellow, which means non-editable and only for display. The form changes back as the initial status, non-editable.

Cancel command

Use **Cancel** command to close the form, without saving any update data.

Month Data List command

Use the **Month Data List** command to be prompted to review the list of all the unit month data on the form of **Error! Bookmark not defined.**

Help command

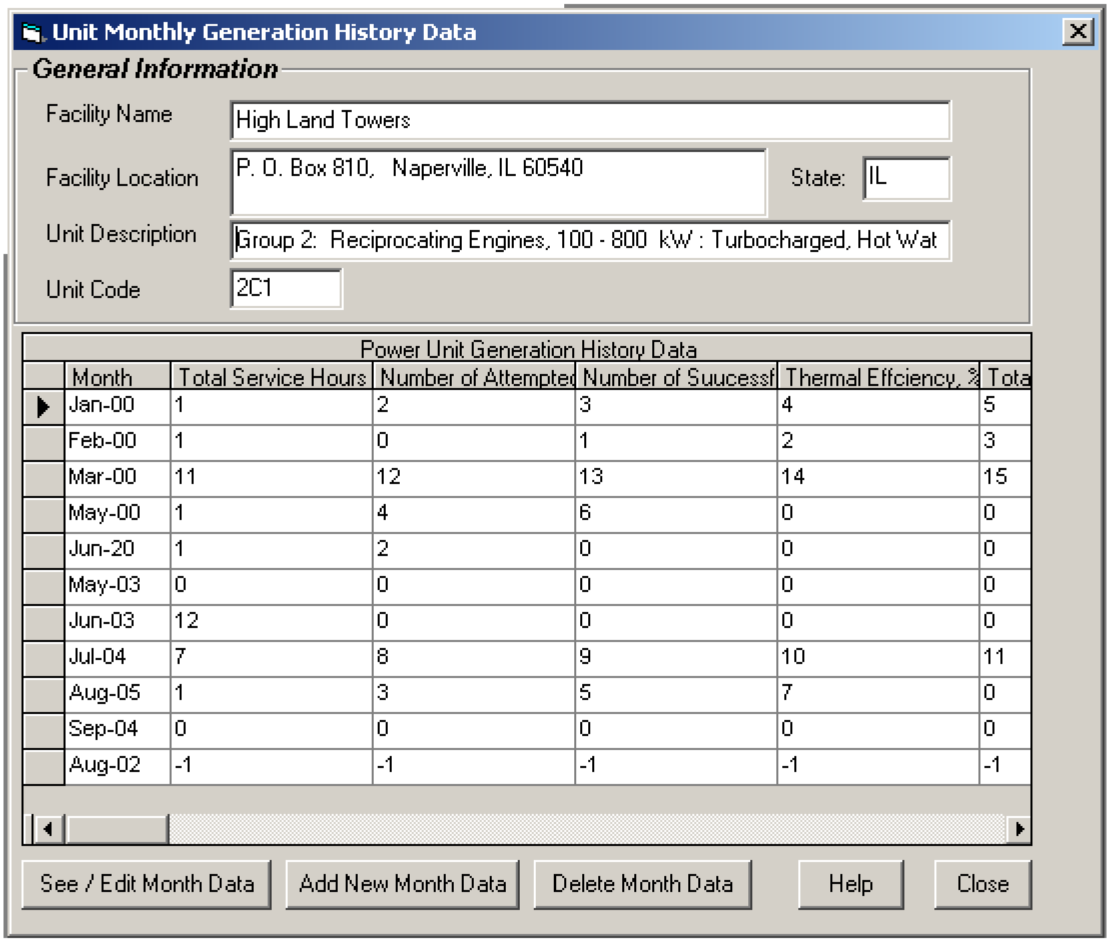
Use **Help** command to show the on-line help information for this form.

Close (OK) command

Use **Close (OK)** command to close the form, without (with) saving the update data.

Unit Monthly Generation History Data

Unit Monthly Generation History Data form is used to show all the monthly data for the Unit. Also, it provides users options to review, edit, add and delete monthly data.


Unit Monthly Generation History Data

General Information

Facility Name: High Land Towers

Facility Location: P. O. Box 810, Naperville, IL 60540 State: IL

Unit Description: Group 2: Reciprocating Engines, 100 - 800 kW : Turbocharged, Hot Wat

Unit Code: 2C1

Power Unit Generation History Data

Month	Total Service Hours	Number of Attempted	Number of Suucessf	Thermal Effciency, %	Tota
Jan-00	1	2	3	4	5
Feb-00	1	0	1	2	3
Mar-00	11	12	13	14	15
May-00	1	4	6	0	0
Jun-20	1	2	0	0	0
May-03	0	0	0	0	0
Jun-03	12	0	0	0	0
Jul-04	7	8	9	10	11
Aug-05	1	3	5	7	0
Sep-04	0	0	0	0	0
Aug-02	-1	-1	-1	-1	-1

See / Edit Month Data | Add New Month Data | Delete Month Data | Help | Close

<u>**Unit Monthly Generation History Data Commands**</u>

See / Edit Month Data command

Use the **See / Edit Month Data** command to be prompted to review or edit the related month data for the unit on the form of **Error! Bookmark not defined.** One specific month should be highlighted from the month list before clicking on the command.

Add New Month Data command

Use the **Add New Month Data** command if you need to add a new Month Data for the unit. When you choose the Add New Month Data command, you will be prompted to specify a new Month / Year and the related data on the form of **Error! Bookmark not defined.**

.

Deleted Month Data command

Use **Delete Month Data** command if you need to delete the month Data for the unit from the DGRST database**.** One specific month should be highlighted from the month list before clicking on the command. **Warning**: once completion of the command, all the month data will be deleted and can not be undone.

Help command

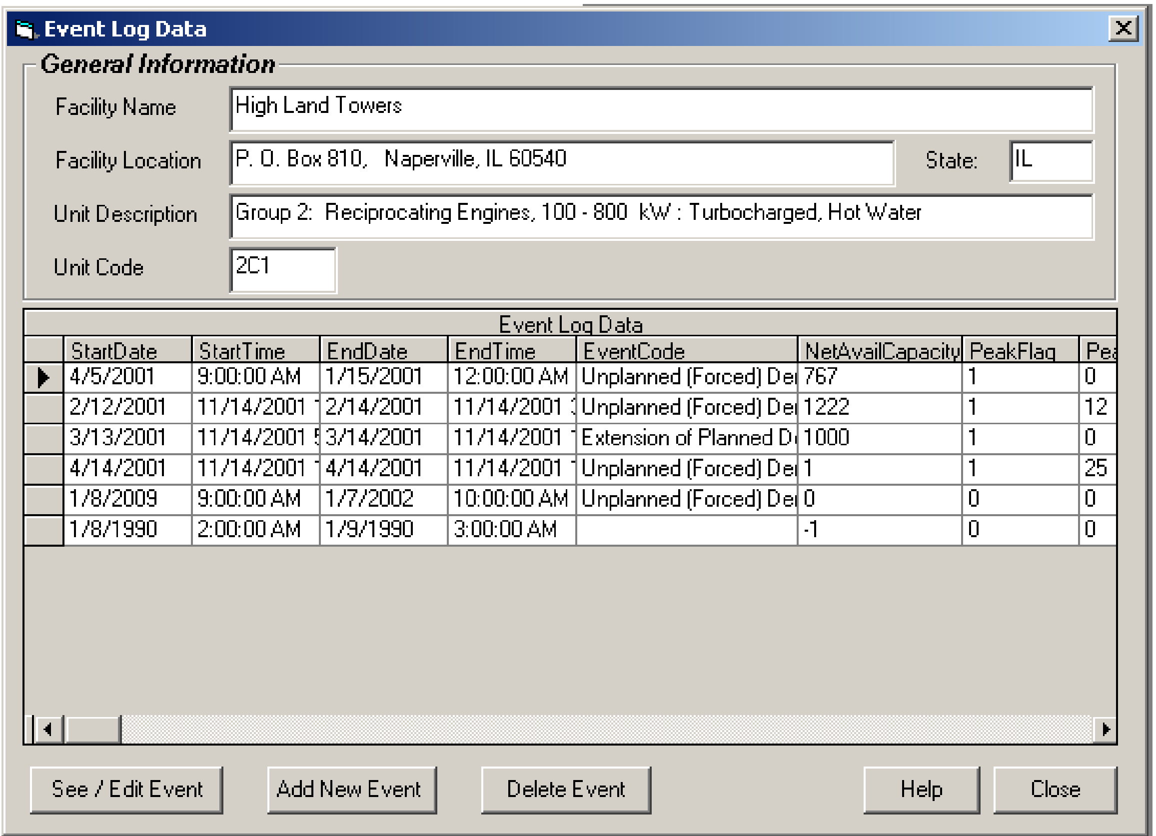
Use **Help** command to show the on-line help information for this form.

Close command

Use **Close** command to close the form.

Event Log Data

Event Log Data form is used to show all the events for one unit. Also it provides users option to review, edit, add and delete the event for the unit.


Event Log Data

General Information

Facility Name: High Land Towers

Facility Location: P. O. Box 810, Naperville, IL 60540 State: IL

Unit Description: Group 2: Reciprocating Engines, 100 - 800 kW : Turbocharged, Hot Water

Unit Code: 2C1

Event Log Data

StartDate	StartTime	EndDate	EndTime	EventCode	NetAvailCapacity	PeakFlag	Pea
4/5/2001	9:00:00 AM	1/15/2001	12:00:00 AM	Unplanned (Forced) De	767	1	0
2/12/2001	11/14/2001	2/14/2001	11/14/2001	Unplanned (Forced) De	1222	1	12
3/13/2001	11/14/2001	3/14/2001	11/14/2001	Extension of Planned D	1000	1	0
4/14/2001	11/14/2001	4/14/2001	11/14/2001	Unplanned (Forced) De	1	1	25
1/8/2009	9:00:00 AM	1/7/2002	10:00:00 AM	Unplanned (Forced) De	0	0	0
1/8/1990	2:00:00 AM	1/9/1990	3:00:00 AM		-1	0	0

See / Edit Event | Add New Event | Delete Event | Help | Close

<u>Event Log Data Commands</u>

See / Edit Event command

Use the **See / Edit Event** command to be prompted to review or edit the related information for the event on the form of **Error! Bookmark not defined.**. One specific event should be highlighted from the event list before clicking on the command.

Add New Event command

Use the **Add New Event** command if you need to add a new event for the plant. When you choose the Add New Event command, you will be prompted to specify a new event and its related information on the form of **Error! Bookmark not defined.**

.

Deleted Event command

Use **Delete Event** command if you need to delete the event Data for the unit from the DGRST database**.** One specific event should be highlighted from the month list before clicking on the command. **Warning**: once completion of the command, the event data will be deleted and can not be undone.

Help command

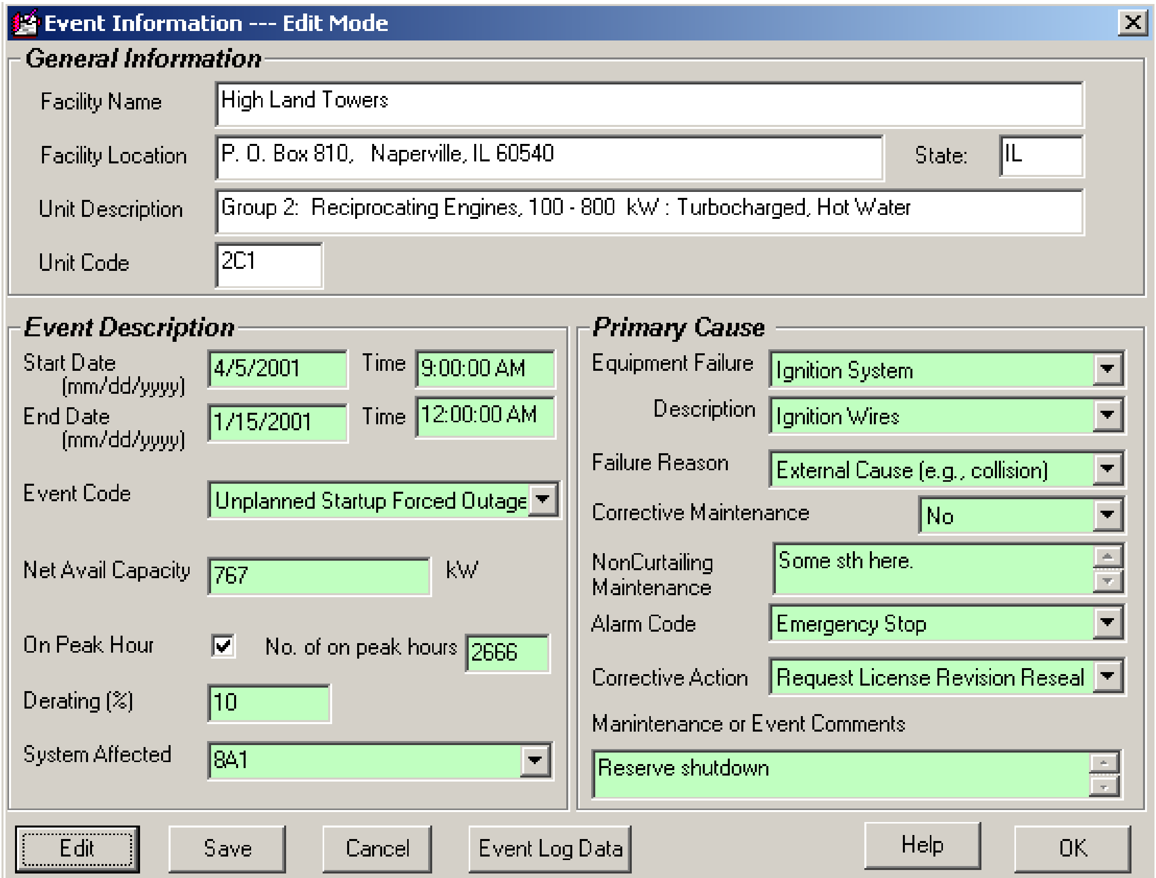
Use **Help** command to show the on-line help information for this form.

Close command

Use **Close** command to close the form

Event Information

Specific event data for one unit can be reviewed / edited on this form.



<u>Event Information Commands</u>

Edit command

Use **Edit** command to change the form into the editable mode. The data in the box with light green color can be edited directly. After Edit command executing, Save command will be enabled for saving the update data, and Close command will change to OK command for saving the update data and closing the form.

Save command

Use **Save** command to save all the data on the form. After Save command executing, the form change back to un-editable mode. The back color in data boxes will be light yellow, which means non-editable and only for display. The form changes back as the initial status, non-editable.

Cancel command

Use **Cancel** command to close the form, without saving any update data.

Event Log Data command

Use the **Event Log Data** command to be prompted to review the list of all events for the unit on the form of **Error! Bookmark not defined.**

Help command

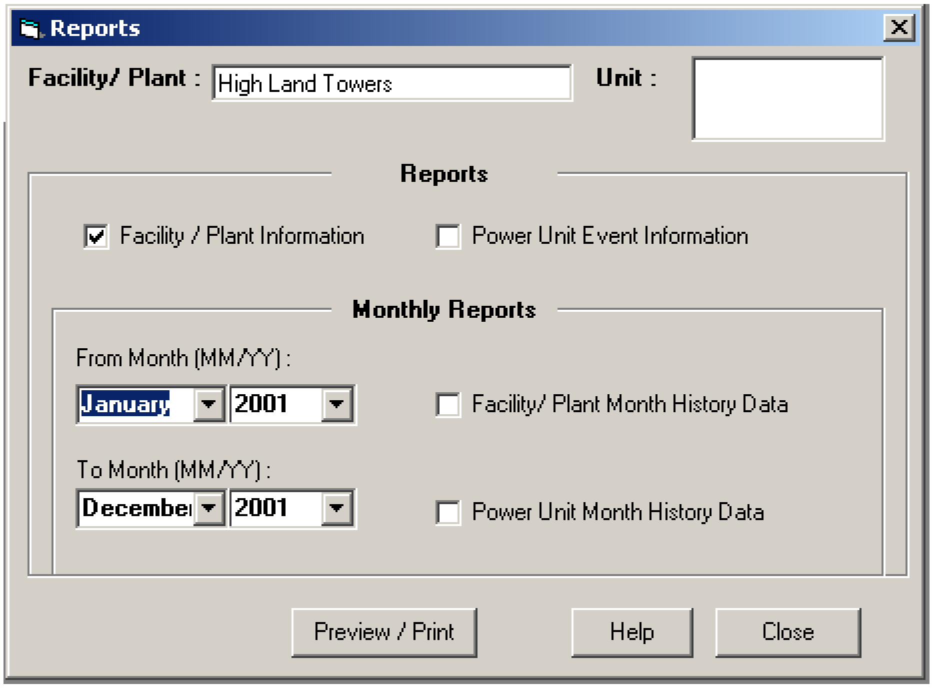
Use **Help** command to show the on-line help information for this form.

Close (OK) command

Use **Close (OK)** command to close the form, without (with) saving the update data.

Reports

The reports for plant data, unit data, event data, and monthly generation data can be previewed and printed after the specific report(s) selected.



<u>Reports Commands</u>

Help command
Use **Help** command to show the on-line help information for this form.

Close command
Use **Close** command to turn off the form.

Preview / Print command
Use **Preview / Print** command to preview or print the selected report(s).

APPENDIX C DG/CHP RELIABILITY DATABASE

APPENDIX D

TECHNOLOGY/DUTY CYCLE SUMMARY REPORTS AND UNIT CHARACTERIZATION REPORTS

Case No. U-18255
Exhibit MCA-5

Energy solutions
for a changing world

Standby Rates for Combined Heat and Power Systems

Economic Analysis and Recommendations for Five States

Authors

James Selecky

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Ali Al-Jabir

February 2014

ORNL/TM-2013/583

Standby Rates for Combined Heat and Power Systems:

Economic Analysis and Recommendations for Five States

**Prepared by Brubaker & Associates, Inc.
and the Regulatory Assistance Project
for Oak Ridge National Laboratory**

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Final editor: Richard Sedano, Regulatory Assistance Project

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Electronic copies of this paper and other RAP publications can be found on our website at **www.raponline.org**.

To be added to our distribution list, please send relevant contact information to **info@raponline.org**.

RAP

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List of Acronyms and Abbreviations

AG	Average Generation
BAI	Brubaker & Associates, Inc.
BD	Billing Demand
CD	Contract Demand
CHP	Combined Heat and Power
CP	Coincident Peak Demand
CRES	Certified Retail Electric Service
DOE	(U.S.) Department of Energy
DR	Demand Rate
EAI	Entergy Arkansas, Inc.
EV	Expected Value
FERC	Federal Energy Regulatory Commission
FOR	Forced Outage Rate
GW	Gigawatts
kW	Kilowatts
LGS	Large General Service
LPS	Large Power Service
MM	Maximum Monthly
NCP	Non Coincident Peak Demand
OAD-SBS	Open Access Distribution Standby Service
OATT	Open Access Transmission Tariff
ORNL	Oak Ridge National Laboratory
PSCo	Public Service Company of Colorado
PURPA	Public Utility Regulatory Policies Act
RAP	Regulatory Assistance Project
RMP	Rocky Mountain Power
SBS	Standby Service
SR	Standby Rate
SSO	Standard Service Offer
SSR	Standby Service Rider
STB	Standby Service Rider
VAR	Voltage Adjustment Rider

Foreword

Improvements in technology, low natural gas prices, and more flexible and positive attitudes in government and utilities are making distributed generation more viable. With more distributed generation, notably combined heat and power, comes an increase in the importance of standby rates, the cost of services utilities provide when customer generation is not operating or is insufficient to meet full load.

This work digs into existing utility standby tariffs in five states. It uses these existing rates and terms to showcase practices that demonstrate a sound application of regulatory principles and ones that do not.

In cases where we find deficiencies, it is not to embarrass, but rather to call attention to opportunities for improving a set of rates that are often governed by the outmoded idea that distributed generation is rare and inherently risky to utility operations and customers. Also, these rates do not get a lot of attention and likely are due for reassessment soon in many jurisdictions.

Trends show that distributed generation is not rare anymore and that old ideas about risk have been replaced by utility operator confidence in anticipated performance, which stems from interconnection agreements and probabilistic assessments. Rates and charges that may have been set roughly can be modified to apply better matching of utility costs with the services customers use. The context for this work, then, is part of a trend to a more customer-focused utility sector that not only looks to provide good service, but looks to the consumer as a resource.

We find many areas for improvement in standby rates. Will utilities and their regulators take steps to consider and execute these changes? Time will tell, but with technology driving applications and deployment, utilities and their regulators will be hard-pressed to do any less than steward this progress.

Richard Sedano
Director, US Programs
Regulatory Assistance Project

Executive Summary

Standby, or partial requirements, service is the set of retail electric products for customers who operate onsite, non-emergency generation. Utility standby rates cover some or all of the following services:

- **Backup power** during an unplanned generator outage;
- **Maintenance power** during scheduled generator service for routine maintenance and repairs;
- **Supplemental power** for customers whose onsite generation under normal operation does not meet all of their energy needs, typically provided under the full requirements tariff for the customer's rate class;
- **Economic replacement power** when it costs less than onsite generation; and
- **Delivery** associated with these energy services.

This paper presents the results of an analytical assessment of the rates, terms, and conditions for standby service in five states: Arkansas, Colorado, New Jersey, Ohio, and Utah. Specifically the study evaluated the efficacy of standby tariffs for combined heat and power (CHP) applications.

This paper sets forth options to improve the tariffs analyzed and the estimated economic impact of the suggested tariff improvements for a selected set of proxy utility customers who have CHP systems. Although the study and recommendations targeted participating states, the analytical methods, spreadsheets, and recommendations can be adapted for use by other jurisdictions.[1]

Selection of States and Tariffs for Analysis

The Regulatory Assistance Project (RAP) identified candidate states for the project considering geographic diversity, representation of states with restructured electricity markets as well as those that remain vertically integrated, and the jurisdictions' interest in reviewing standby tariffs.

To keep the project manageable, RAP and Brubaker & Associates, Inc. (BAI) worked with state regulatory commission staff to select a single investor-owned utility for tariff evaluation:

State	Utility	Tariff(s)
Arkansas	Entergy Arkansas, Inc.	*Standby Service Rider*
Colorado	Public Service Company of Colorado	*Schedule PST* *Schedule TST*
New Jersey	Jersey Central Power & Light Company	*Rider STB*
Ohio	AEP-Ohio Power Company	*Schedule SBS* *Schedule OAD-SBS*
Utah	Rocky Mountain Power	*Schedule 31*

Coordination With State Regulatory Commissions

RAP and BAI presented the results of the economic analysis and recommendations to regulatory commission staff and provided an opportunity for review and comment. In some cases, public workshops were held with commissioners, utility representatives, affected customer groups, and other stakeholders. This interactive process informed and enhanced the development of the analyses and recommendations presented in this paper.

Description of Analytical Methods

BAI estimated economic impacts of the standby tariffs using an Excel spreadsheet model customized for each tariff analyzed. The model calculates standby service costs under the currently effective standby rates. When practical, models were also used to calculate the costs resulting from the tariff modifications.

1 For state specific attachments and a link to the Excel model for each state, please go to: http://www.raponline.org/featured-work/standby-rates-for-CHP

Standby Rate Tariff Structures

While standby rates vary widely, they typically include the following:

- A ***capacity reservation charge*** is a charge to compensate the utility for the capacity that the utility must have available to serve a customer during an unscheduled outage of the customers own generation unit.
- ***Capacity and energy charges*** for the actual electricity supplied to a customer during an unscheduled outage of the customer's own generation unit.
- A ***maintenance capacity charge*** for the capacity supplied by the utility during a scheduled outage of the customer's own generation unit, and,
- ***facility charges*** to compensate the utility for any dedicated distribution costs.

Summary of Best Practices in Standby Rate Design

Based on the experience of RAP and BAI in the area of standby rate design, explained in Chapter 1, the following are best practices for consideration in the development of standby rates:

Allocation of Utility Costs

- Generation, transmission, and distribution charges should be unbundled in order to provide transparency to customers and enable appropriate and cost-based standby rate design.
- Supplemental power charges should be based on charges in the applicable full requirements tariff.
- Generation reservation demand charges should be based on the utility's cost and the forced outage rate of customers' generators on the utility's system.

Judgments Based on Statistical Method

- Standby rate design should not assume that all forced outages of on-site generators occur simultaneously, or at the time of the utility system peak.
- Transmission and higher-voltage distribution demand charges should be designed in a manner that recognizes load diversity.
- Standby rate design should assume that maintenance outages of on-site generators would be coordinated with the utility and scheduled during periods when system generation requirements are low.

Value of Customer Choice and Incentives

- Daily maintenance demand charges should be discounted relative to daily backup demand charges to recognize the scheduling of maintenance service during periods when the utility generation requirements are low.
- Customers should have the option to purchase all or some portion of their standby service on an interruptible basis and thereby avoid generation reservation demand charges.
- Pro-rated, daily, as-used demand charges for backup power and shared transmission and distribution facilities should be used to provide an incentive for generator reliability.
- Customers should be able to procure standby service from competitive power providers at prevailing market prices, where available.

Recommendations for Standby Tariff Modifications

Based on RAP's and BAI's experience in standby rate design and the analyses conducted by the study's authors, the following are potential modifications to the rate designs, terms, and conditions of the standby tariffs analyzed. Descriptions of the current tariffs appear in the corresponding chapters.

Arkansas – Entergy Arkansas Inc.'s (EAI) Standby Service Rider SSR (Chapter 3)

- The reservation demand charge should be unbundled into generation, transmission, and distribution components.
- The unbundled generation component of the reservation demand charge for standby service should be set such that it is equivalent to the best FOR exhibited by any generating unit on EAI's system.
- The reservation demand charge should be differentiated by season.
- The daily backup and maintenance demand charges should apply only during on-peak periods.
- The daily backup and maintenance energy charges should be differentiated on a time of-use basis.
- Customer-generators should have the option to buy backup power from the market through the utility and avoid monthly reservation charges for standby generation service.
- The Non-Reserve Service feature of Rider SSR should be modified to facilitate the provision of interruptible standby service.

- Standby charges for shared transmission and distribution facilities should reflect load diversity.
- Standby charges should be concise and easily understandable. Customers who may consider installing a CHP system may have a difficult time understanding all of the charges they may pay under various circumstances with the standby tariffs and riders EAI has in place today.
- The standby tariffs should specify the circumstances under which a special contract may be warranted.

Colorado – Public Service Company of Colorado (PSCo) Schedules PST and TST (Chapter 4)

- The Grace Energy Hours provision should be eliminated and replaced with a lower generation reservation fee coupled with a daily demand charge.
- The generation reservation fee should reflect the best FOR exhibited by any customer's generating unit on PSCo's system.
- Daily demand charges should be implemented to provide incentives to improve the performance of self-generating units.
- The standby backup demand charges for generation, transmission, and certain distribution costs should apply only during on-peak hours.
- Customers should have the option to buy backup power at prevailing market prices through the utility if available and thereby avoid standby generation charges.
- Customer-generators should have the option to provide the utility with a load reduction plan that demonstrates their ability to reduce a specified amount of load (in kilowatts [kW]) within a required timeframe and avoid standby generation charges.
- Standby rates for shared distribution facilities should reflect load diversity.
- The generation and transmission cost components of the reservation fee should be unbundled.

New Jersey – Jersey Central Power & Light Company Standby Service Rider STB (Chapter 5)

- Scheduled maintenance hours should be allowed for all standby customers. The tariff states that customers who commence service after February 25, 1993 are not allowed to schedule maintenance for their generating units.
- Standby service should be available to all customer-generators regardless of the availability factor of their generating unit.
- Standby tariffs should be concise and easily understandable. Customers may have difficulty understanding this tariff because of the different types of demand measurements and the manner in which charges are assessed.
- Standby charges for shared distribution facilities should reflect load diversity.[2]

Ohio – AEP-Ohio Power Company's Schedules SBS and OAD-SBS (Chapter 6)

- Generation reservation charges should reflect the best FOR exhibited by any generating unit on the system.
- Daily demand charges should be developed to provide incentives to improve generator performance.
- Customers should have the option to buy backup power from the market.[3]
- Charges for distribution facilities should reflect load diversity.
- The distribution component of the reservation charge should be adjusted to include only the cost associated with dedicated distribution facilities. The tariffs should be concise and easily understandable.
- The tariffs should specify that special circumstances may warrant a special contract.

2 Rider STB may already recognize load diversity. The standby distribution charges are substantially below the full requirements service distribution charges.

3 By the end of 2015, all customers of AEP-Ohio Power Company will be able to choose an alternative electricity supplier.

Utah – Rocky Mountain Power Schedule 31 and Schedule 33 (Chapter 7)

- The on-peak backup charges should be calculated and stated on a seasonal basis.
- The generation reserve charge should be modified to reflect the performance of the best generating unit.
- The shared transmission and distribution standby demand charges should be adjusted to reflect load diversity.
- The distribution component of the reservation charge should be adjusted to include only the cost associated with dedicated distribution facilities.
- Customers should have the option to buy backup power from the market through the utility and thereby avoid backup charges for standby power.
- Customers should have the option to provide the utility with a load reduction plan that demonstrates their ability to reduce a specified amount of load (kW) within a required timeframe to mitigate all, or a portion of, the backup demand charges.
- Customers should be allowed to take a total of up to 30 days of maintenance power per year without the current constraint of taking this service only twice during the year.

Introduction

Standby, or partial requirements, service is the set of retail electric products for customers who have onsite, non-emergency generation, such as combined heat and power (CHP). By simultaneously producing useful electric and thermal energy from a single fuel source at a customer's site, CHP enhances energy efficiency, improves environmental quality, and makes businesses more competitive.

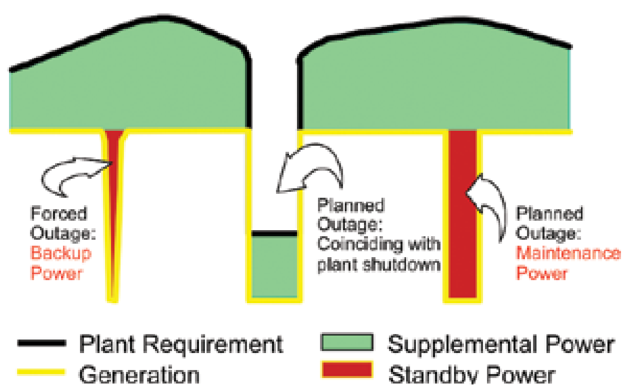
Utility standby rates cover some or all of the following standby services (see Figure 1):[4]

- ***Backup power*** during an unplanned generator outage;
- ***Maintenance power*** during scheduled generator service for routine maintenance and repairs;
- ***Supplemental power*** for customers whose onsite generation under normal operation does not meet all of their energy needs, typically provided under the full requirements tariff for the customer's rate class;
- ***Economic replacement power*** when utility power costs less than onsite CHP generation; and
- ***Delivery*** associated with these energy services.

On August 30, 2012 President Obama issued an Executive Order[6] that sets a goal of 40 gigawatts (GW) of new, cost-effective industrial CHP in the United States by 2020, a 50-percent increase from today. Meeting this goal would save energy users an estimated $10 billion per year, result in $40 to $80 billion in new capital investment in manufacturing and other facilities, create American jobs, and reduce emissions equivalent to 25 million cars.

Figure 1

Illustration of Self-Generating Customers' Purchase Power Requirements[5]



Standby rates are an important factor in determining the relative economics of CHP applications, compared to taking full requirements service from an electric utility or alternative electricity supplier. Charges or terms and conditions of a standby tariff that would result in excessive costs for standby service would unnecessarily discourage CHP development, an inherently more energy-efficient technology than taking traditional utility or alternate supplier power.

RAP and others have documented best practices in standby rate design and utility tariffs that exemplify these principles.[7,8] Building on this foundation, RAP recruited state regulatory commissions to work with a technical consultant to review standby tariffs in place today against these approaches and take preliminary steps to consider tariff improvements to facilitate adoption of CHP systems.

With funding from the U.S. Department of Energy (DOE) and under contract to Oak Ridge National Laboratory (ORNL), RAP hired Brubaker & Associates, Inc. (BAI) to perform the economic analysis of standby tariffs in five states, work with RAP to recommend possible tariff modifications that could improve their efficacy for CHP applications, and quantify the potential economic impact of the recommended improvements for proxy industrial and commercial customers.

RAP and BAI conducted a preliminary assessment of standby rates in selected states to identify tariffs that

4 In restructured states, the utility may provide only delivery services and provider-of-last-resort energy service.

5 Source: Brubaker & Associates.

6 The White House, Office of the Press Secretary, 2012.

7 See, in particular, Weston, et al., 2009. For examples of current utility standby practices, see Stanton, 2012.

8 Johnston, et al., 2008.

Table 1

Selected Utilities and State Regulators

Utility	Regulatory Jurisdiction
Ohio Power Company (AEP)	Public Utilities Commission of Ohio
Entergy Arkansas, Inc.	Arkansas Public Service Commission
Rocky Mountain Power Company (PacifiCorp)	Public Service Commission of Utah
Public Service Company of Colorado	Colorado Public Utilities Commission
Jersey Central Power & Light Company (FirstEnergy)	New Jersey Board of Public Utilities

present opportunities for improvement that would make them more attractive for CHP applications, while adhering to ratemaking principles. To some extent, the selection process was random. However because cooperation was needed from the state regulatory agencies, consideration was given to states where there was a past working relationship with RAP. In cooperation with regulatory utility commission staff, one utility per state was selected for detailed tariff review and analysis (see Table 1).

The tariffs were first analyzed at a conceptual level to understand each component and the manner in which these components interact with one another, associated tariff riders, and applicable full requirements tariffs. The project team then identified specific areas where tariff modifications could be made to reduce hurdles to installation of cost-effective CHP systems. BAI developed a Microsoft Excel model for each state to quantify the economic impact of the tariffs currently in place and evaluate the proposed tariff enhancements. The model runs use only publicly available information: (1) the rates, terms, and conditions in the relevant tariffs, and (2) customer usage and load characteristics, standby power needs, and generator sizes and types developed by each state project team to represent industrial and commercial customers with promise for adopting CHP.

This report is organized into three major sections:

- **Best Practices in Standby Rate Design** sets forth basic concepts for understanding the economics of standby rate design, discusses the economic and policy criteria that establish the foundation for good standby rate designs, and describes best practices in standby rate design.
- **Economic Analysis for Study** discusses the process for the selection of representative customer-generators for analysis, describes the process used to identify potential improvements and enhancements to the standby tariffs analyzed in the study, and discusses the modeling methods and assumptions used to quantify the potential economic impact of the proposed tariff improvements.
- **State-Specific Standby Rate Analyses** describe the standby tariffs examined, assess the efficacy of the tariffs for CHP applications, recommend improvements to the tariffs, and present the economic analysis.

Appendices to this document (available online) include the standby power tariffs surveyed, detailed results of economic analyses performed for this study, work papers supporting the analysis and recommendations, and a list of resources for additional information on standby rates.

Definition of Key Concepts

Following are central rate design concepts important for understanding the economic rationale behind the design of standby rates.

Backup power is electric capacity and energy supplied by an electric utility during an unscheduled outage of the customer's on-site generation. Thus, backup power is supplied by the utility on a random basis to replace capacity and energy ordinarily generated by a customer's own generation equipment.

Capacity/demand charges are charges based on a customer's highest usage in a one hour or shorter interval during a billing cycle.

Energy charges are the part of the charge for electric service based upon the electric energy consumed or billed.

Maintenance power is electric capacity and energy supplied by an electric utility during scheduled outages of the customer's on-site generation. This type of power is provided on a prearranged, scheduled basis to allow the customer to take its equipment out of service for routine inspections and preventive maintenance.

Demand Ratchets: Some tariffs set the billing demand at the higher of (1) the current month's measured demand or (2) a fraction (typically 60 or 90 percent, but sometimes as much as 100 percent) of the customer's highest measured demand in the previous year or in the past peak season. This type of pricing is referred to as a "demand ratchet."[9]

Reserve Capacity/Reserve Margin/Reserves are the amount of capacity that a system must be able to supply, beyond what is required to meet demand, in order to assure reliability when one or more generating units or transmission lines are out of service. Traditionally a 15-20 percent reserve capacity was thought to be needed for good reliability. In recent years, the accepted value in some areas has declined to 10 percent.

Supplemental power is electric capacity and energy supplied by an electric utility that is regularly used by a self-generating customer in addition to capacity and energy from on-site generation. Because this service usually is available "around the clock" and on a "firm" basis, supplemental power is the same as full requirements service for non-generating customers. Supplemental power is typically charged at the otherwise applicable full-requirements tariff rates.

Coincidence factor is the ratio of a customer's coincident peak demand (CP) to its non coincident peak demand (NCP), or billing demand. A customer's CP is the demand imposed by the customer at the time of the utility system's maximum demand. The customer's NCP is the customer's maximum demand recorded at any time during a specified time interval. CP and NCP may be measured on a monthly or annual basis. Table 2 illustrates how coincidence factor is determined.

Table 2

Illustrative Coincidence Factors

Customer	Coincident Demand (kW)	Billing or Non-Coincident Demand (kW)	Coincidence Factor*
FR1	1,000	2,000	50%
FR2	1,000	1,250	80%

* *Column 1 ÷ Column 2*

Both customers, FR1 and FR2, purchase full requirements service and impose a 1,000-kW CP demand on the system. Customer FR1 has a NCP demand of 2,000 kW, while the NCP demand of Customer FR2 is 1,250 kW. Thus, Customer FR1 has a 50-percent coincidence factor (1,000 kW/2,000 kW), while Customer FR2 has an 80-percent coincidence factor (1,000 kW/1,250 kW).

The Forced Outage Rate (FOR) of a generating unit for a given time interval is defined as the number of hours that the unit is forced out of service for emergency reasons, divided by the total number of hours that the generating unit is available for service during that time interval plus the number of hours that the generating unit experiences a forced outage. The FOR of a generating unit measures the probability that the unit will not be available for service when required. Essentially the FOR provides an indication of the percentage of time that a generating unit is forced out of service for emergency reasons. The FOR is a measure of a generating unit's reliability.

9 Lazar, 2013.

Chapter 1. Best Practices in Standby Rate Design

Standby rates are typically designed to recover the fully allocated embedded costs that the utility incurs to provide standby service to self-generating customers and, for investor-owned utilities, a reasonable rate of return established by the applicable state regulatory commission. The federal Public Utility Regulatory Policies Act (PURPA) established the fundamental cost of service and legal principles that govern the design of standby rates. These principles have been implemented on a state-by-state basis through state regulatory commission rules and rate orders that establish utility-specific tariffs of general applicability for the provision of standby power.

In competitive electricity markets, market prices determine the charges for standby service from electricity suppliers. Generally the electricity cost of backup power (distinct from the delivery[10] costs) is determined by the market price at the time of the customer-generator's outage.

Economic and Policy Principles Governing the Design of Standby Rates

In general, state regulatory utility commissions require that standby rates be based on the same cost-of-service principles that are applied to the utility's full requirements customers. These rate design principles are consistent with the requirements of PURPA that:[11]

> *Rates for sales shall be just and reasonable and in the public interest and shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.*
>
> * * * *
>
> *Rates for sales which are based on accurate data and consistent with system-wide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.*

In other words, a self-generating customer should not pay more for purchased electricity from the utility than other customers having similar load and other cost-related characteristics (size, delivery voltage, and so on).

A critical issue in designing cost-based standby rates is determining the appropriate level of generation reserve capacity that a utility must carry to provide standby service to self-generators on its system. The required level of utility reserves to support standby service is a function of generator resource reliability. A self-generator having greater reliability than utility controlled resources may require reserves lower than the utility average. On the other hand, a self-generator with below-average reliability could require above-average reserves. A precise determination can only be made through long-run observed performance of the facilities in question. Methods to design prices for standby service, standby generation reservation, and daily as-used demand will be summarized in the rest of the paper. These rates and methods are also demonstrated in the online companion Excel spreadsheets with this report.

Impact of Coincidence Factor on Standby Power Requirements

Standby customers have different load characteristics than non-generating (i.e., full-requirements) customers. Whereas full-requirements customers typically impose load on the utility system 365 days a year, a reliable standby customer requires backup power only on a handful of days during random generator outages.

The effect is that a utility supplying standby power will not have to plan as much reserve capacity to serve self-generating customers as it does for full-requirements customers. There are two reasons for this. First, not all customer-generators will require standby power at the same time. Second, it is highly unlikely that such purchases will coincide with the system peak. A customer having a low coincidence factor should pay less per kW of non coincident peak, or billing demand, than another

10 "Delivery" as used in this paper is synonymous with "transmission and distribution."

11 18 C.F.R § 292.305 (1)(i)(ii) and (2).

Table 3

Impact of Coincidence Factor on Demand Charges

Customer	1. Coincident Demand (CP kW)	2. Billing Demand (BD kW)	3. Coincidence Factor	4. Demand Costs*	5. Demand Charge** ($/kW)
FR1	1,000	2,000	50%	$10,000	$5.00
FR2	1,000	1,250	80%	$10,000	$8.00
Standby	1,000	20,000	5%	$10,000	$0.50

** The demand costs are the same because they are allocated relative to coincident demand.*
*** Column 4 ÷ Column 2*

customer having a higher coincidence factor. Generally the utility system is large enough to accommodate the needs of its self-generating customers.

Coincidence factor is relevant in designing rates because most electric utilities bill for demand on a non-coincident basis. A customer having a higher coincidence factor will impose higher demand-related costs per kW of billing demand than a customer having a lower coincidence factor. Table 3 illustrates this point.

All three customers illustrated in Table 3 impose the same coincident demand on the utility, and total demand costs are allocated relative to coincident demand. Customers FR1 and FR2 purchase full requirements service and have a coincidence factor of 50 percent and 80 percent, respectively. This is typical of a utility's full requirements customers. The standby customer, by contrast, has a five-percent coincidence factor. This may be reflective of backup power requirements over time. In some years, a forced outage may occur coincident with the peak. In other years, it may not.

All other things being equal, the lower the coincidence factor, the lower the per-unit standby demand charge needed. This is because there are more billing units (Column 2) over which to spread the allocated demand-related costs (Column 4) for backup power than for full-requirements service. Whereas a $5/kW or $8/kW demand charge would be appropriate for full requirements customers, a reliable standby customer should be charged only a fraction of these amounts for standby power, or $0.50/kW, based on the previous example.

Backup and maintenance service do not have the same coincidence with the system peak as full requirements utility service. Whether backup power service is more or less coincident than full-requirements utility service depends on the reliability of the customer's generating unit. Maintenance power, as typically defined by utility tariffs, would only be provided during times of the year when the utility has adequate generating resources available. It could therefore be argued that properly scheduled maintenance power would have a coincidence factor near zero. Forced outages, by contrast, are more random in nature.

These distinctions between the nature of backup and maintenance service have important rate design implications. Specifically, the rates for backup power service should reflect the fact that the utility is providing only the reserve capacity. Properly scheduled maintenance power service rates should reflect both the lower cost and the off-peak nature of this service. It is a lower cost service than firm backup power because utilities generally require maintenance service to be scheduled in advance, and service may be refused if adequate resources are not available to accommodate a planned outage. This lower quality of service should be reflected in the form of a price discount for maintenance power relative to backup power service.

PURPA recognizes that backup and maintenance services are different from regular utility service. The rules state:[12]

Rates for sales of backup and maintenance power. The rate for sales of backup power or maintenance power:

(1) shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(2) shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

Generator Reliability and Standby Rate Design

The expected standby load on a utility's system represents the level of standby demand that the utility is obligated to serve. Mathematically this can be expressed as the FOR times the maximum or contract demand of the self-generating customers. In some hours, the utility's actual standby load will be greater than the expected

12 18 C.F.R § 292.305 (2c)(1) and (2).

value. In other hours, it will be less than the expected value. And in many hours, it will be zero. Unlike full requirements loads, standby customers generally will not place as much of their total contracted demand on the utility during peak periods.

The reliability of self-generators affects the cost of providing backup service. The fundamental economic principle underlying the design of backup power rates is that a utility providing backup service is incurring the costs associated with the reserve capacity, which in conjunction with the self-generating capacity, assures a reliable supply of electricity to the customer. Highly reliable self-generators will require small reserve levels; less reliable self generators will require larger reserve levels.

Costing and Pricing Standby Service

One reasonable approach to costing and pricing the generation component of standby service is to quantify the amount of reserve capacity required to provide firm standby service based on an expected level of standby demand that the utility will serve over time. This can be done independently of a class cost-of-service study.

One means of establishing the generation-related costs of providing standby service is the Expected Value (EV) method, a methodology for quantifying the amount of reserve capacity required to provide standby service. The EV method is a reasonable approach for at least two reasons. First, the EV method is easy to implement. Second, this method is consistent with cost-of-service principles in that it directly measures the probability that standby customers will or will not contribute to the need for, and use of, generation capacity.

Under this method, the amount of reserve capacity required to provide standby service is equal to the product of the FOR and the standby contract capacity. The FOR used in the EV method should reflect the long-run performance of customer-owned generation facilities. The FOR used in the EV method directly reflects the probability that an outage of a self-generating customer will occur in any given hour, and therefore provides a reasonable measure of the amount of capacity that a utility must set aside to provide standby power service.

This approach results in the design of a firm standby power rate that consists of two basic components: (1) a monthly generation reservation charge, and (2) a daily, as used demand charge. These two rate components are discussed in more detail herein.

Standby Generation Reservation Charge

The standby generation reservation charge is designed as a percentage of the demand-related generation costs recovered through the regulated demand charges that are assessed to full requirement industrial (or commercial) customers in the jurisdiction under study. The appropriate percentage of the demand charge for generation for full-requirement customers to be assessed to standby customers could be developed using historical data, if available, regarding the FORs of standby customers in the utility's service area. Specifically the standby generation reservation charge would be calculated as the product of the FOR and the demand-related generation costs underlying the applicable full-requirements electricity rate. The standby generation reservation charge rate would be calculated and assessed on a per kW month basis. Recommendations in this paper would use the best performing customer generators (lowest FOR) to set rates to recognize the value of reliable systems. If an average FOR is used to develop the standby generation standby charge, the customers whose self-generating unit is performing the best will be paying rates above the cost to serve. Average and unreliable systems can be motivated to improve through incentives embedded in other rate elements such as the daily demand charge.

This reservation charge would be billed each month of the year as the product of the per kW-month reservation charge rate and the firm standby power demand that the utility commits to provide to the standby customer by contract (the contract demand). The reservation charge would establish a minimum monthly charge that the standby customer would pay, even if the customer did not actually take any standby power service in a given month.

Some customers may wish to contract for standby capacity that fully covers the peak output of their on-site generating units, paying for firm standby service for all of their load at a set price, whereas other customers may desire a somewhat lower level of backup. Allowing individual customers to designate a contract demand specifying the level of standby capacity they wish to purchase gives customers the option to cover only a portion of their load while paying market based pricing for any energy use above that level.

Daily, As-Used Standby Demand Charge

On average, the monthly generation reservation charge would recover the utility's cost of providing firm standby service. When an individual standby customer requires more than the average amount of standby service in a particular billing period, it is appropriate to require the customer to pay additional charges to recognize the additional cost of providing service. For example, if an outage were to last an entire month, a standby customer cost would resemble a full-requirements customer.

A prorated, daily, as-used demand charge would apply when standby service is actually taken in a given billing period. The charge would be designed on a per kW day basis and assessed to the standby customer based on the maximum backup power demand that the customer imposes on the utility's system in a given day.

The standby tariff terms and conditions should make a clear distinction between the purchase of standby power and supplemental power. Without this clear distinction, a customer could be charged for backup power when the power requirement should actually be met through the customer buying supplemental power.

Finally, backup and maintenance power differ from one another and from full requirement power service in that they do not have the same coincidence with the utility's system peak. Maintenance power, by definition, would only be provided during off-peak periods or periods during the year when adequate resources are available. Consequently, it would be reasonable to discount the pro-rated daily demand charges for maintenance power service relative to the daily charges that apply for normal backup power service.

Chapter 2. Economic Analysis for Study

BAI performed an economic analysis of standby tariffs for selected utilities in each of the five states included in the study. The analyses were designed to assist the state regulatory commissions in evaluating the costs and benefits associated with current standby rate designs and potential enhancements. The economic analysis compares the standby costs for specific example CHP systems to determine the impact of existing standby rates and suggested tariff changes on CHP project economics.

BAI developed a Microsoft Excel model for each of the standby tariffs addressed, quantifying the change in costs that would result from implementing the tariff modifications proposed by BAI and RAP. A description of each state-specific model is included online in Attachment 1 to this report. The spreadsheets are also publicly available for other states, customers, and stakeholders to adapt for their own circumstances.[13]

This chapter provides a high-level review of the process that BAI used to develop the economic modeling.

Selection of Representative Customer Usage Characteristics

The first step in developing the economic model for the selected utility tariffs was to designate the representative customer characteristics used to quantify the cost of providing standby service under the existing and alternative proposed rate designs. The customer usage and load characteristics modeled in the study were based on discussions with state regulatory commission staff. In some instances, databases of existing CHP customers in the state, or customer types most likely to develop CHP systems in the state, were used to develop the scenarios studied. However, in each instance the state regulatory staff had the final say as to the size of load that was studied. This also applied to the selection of the forced outage rates that were analyzed.

In general, the process resulted in the selection of characteristics deemed to be appropriate to represent small, medium, and large nonresidential customers.

Description of Modeling Methods

Each model calculates the costs to self-generation customers under various scenarios. Each model allows the user to input representative customer characteristics such as load factor and peak demand, as well as generating unit characteristics such as net capability and assumed outage hours. The spreadsheet includes actual standby service rates for the selected utility, including the core standby tariff and applicable riders and supplemental power tariffs.

Customer and generator characteristics and rate inputs were then used to estimate the cost of taking standby service under the applicable standby rate schedules. After developing the core spreadsheet used to model costs under existing rates, BAI in some instances developed separate spreadsheets to isolate the economic impact of implementing the proposed standby rate modifications recommended by the study for each jurisdiction. In some cases, BAI adjusted rates to simulate the proposed modifications.

Discussion of Modeling Assumptions

Each state model was designed in a manner that allows the user to select assumptions for critical inputs such as forced outage hours, unit maintenance hours, customer load size for both standby and supplemental power requirements, and customer load factor. Once these assumptions are selected, the model calculates the resulting costs under existing tariff rates. This approach gives the user the flexibility to analyze the economic impact of the existing and modified standby rates under a wide range of load and generation assumptions. Depending on the suggested tariff modifications, the model could be used to calculate the revised costs. This would require adjusting the rates in the model that calculates costs under the current tariff.

13 For state specific attachments and a link to the Excel model for each state, please go to: http://www.raponline.org/featured-work/standby-rates-for-CHP

Identifying Potential Tariff Modifications

BAI and RAP developed the potential tariff enhancements recommended in this study in two interrelated steps. First, BAI and RAP reviewed and analyzed the standby tariff components for each selected state utility to understand the rates, terms, and conditions of each tariff; determine how each rate component is calculated; and evaluate the manner in which the various elements of the tariff work together or potentially contradict one another. Second, BAI and RAP evaluated the tariffs against best practices in standby rate design and identified modifications to the tariffs that could enhance their efficacy for CHP applications and move them closer to a best practices model.

A detailed discussion of the proposed tariff modifications for each of the five selected utility standby rates is provided in each state-specific chapter of this report.

Chapter 3. Arkansas

Standby Rates for Customers of Entergy Arkansas, Inc.

Description of Standby Rates

Entergy Arkansas, Inc. (EAI) offers a Standby Service Rider (SSR) under Rate Schedule No. 20. The SSR is available to customers who have their own generating equipment and have executed a contract for standby service with EAI. The SSR is comprised of four service offerings:

1. ***Reserved Service*** is the electric energy and capacity that EAI stands ready to supply during a scheduled or unscheduled outage of the customer's on-site generation equipment.
2. ***Maintenance Service*** is the electric energy and capacity supplied by EAI during scheduled outages of the customer's generating equipment. Maintenance Service is available during the service months of October through May and during the off-peak hours of the service months June through September.
3. ***Non-Reserved Service*** is the electric energy and capacity EAI may supply during a scheduled outage of the customer's on-site generation equipment. Non-Reserved Service is only available during the service months of October through May. EAI, in its sole discretion, may approve or deny any request for Non-Reserved Service.
4. ***Backup Service*** is the electric energy and capacity supplied by EAI during an unscheduled outage of the customer's electric generating equipment, as well as the energy and capacity supplied by EAI during a scheduled outage that exceeds the sum of scheduled Maintenance Service and any scheduled Non-Reserved Service.

Description of Standby Charges

The SSR tariff includes eight charges:

1. A monthly customer charge
2. A monthly reservation charge
3. Seasonal maintenance demand charges expressed on a daily basis
4. Seasonal backup demand charges also expressed on a daily basis
5. A monthly demand charge for Non-Reserved Service
6. Seasonal maintenance energy charges
7. Seasonal backup energy charges
8. Seasonal energy charges for Non-Reserved Service

The reservation demand charge is a flat $/kW-month rate across the entire year. EAI's demand and energy charges for Maintenance and Backup Service vary by season. The seasonal charges are higher during the billing months of June through September (the "Summer Period"), while charges are lower for all other months of the year (defined as the "Other Period"). The tariff defines on-peak hours for the Summer Period and the Other Period. However, SSR rates (except for seasonal maintenance energy charges, as noted above) do not contain any time-of-use differentiation between on-peak and off-peak periods.

SSR demand charges, including the reservation charge, are bundled charges that incorporate generation, transmission, and distribution costs. The reservation charge and the various demand and energy charges vary with the customer's voltage level of service (secondary, primary, or transmission). In addition, these charges are adjusted to reflect the customer's metering points. The energy charges in the SSR are consistent with the energy charges in EAI's full service rates — Large General Service (LGS) and Large Power Service (LPS).

Assessment of Standby Rates

The following are suggested modifications to EAI's standby tariffs for consideration:

- **Lack of transparency and clarity.** None of the EAI rate schedules we reviewed unbundle generation, transmission, and distribution charges, so customers do not know how much they are paying for each component of service and what charges might be avoidable with reliable onsite generation. Furthermore, some provisions of the SSR tariff appear to be in conflict with one another. For example, the tariff indicates that during the months of June through September maintenance energy can only be scheduled during off-peak periods. However, the same provision also states that maintenance service will not be scheduled for a continuous period of less than one day. The latter requirement dictates that maintenance energy must effectively be scheduled during on-peak hours.

- **Lack of price signals to provide incentives to improve operation of on-site generating units and use utility resources more efficiently.** Adding daily demand and energy charges for both backup service and maintenance service could achieve these goals. Daily demand charges could be unbundled into separate charges for the generation, transmission, and distribution cost components. In addition, the generation and transmission components of the demand charge, as well as the charge for non dedicated distribution facilities, could be assessed only during the on-peak period. Furthermore, seasonal energy (per kWh) charges could distinguish on-peak and off-peak usage to better capture the costs that EAI is actually incurring to serve customer-generators.
- **Inadequate interruptible standby service option.** Although the standby tariff allows the customer to purchase Non-Reserved Service, which functions in a similar manner to interruptible service, EAI retains the discretion to deny a customer's request for this service. This means that the SSR tariff does not guarantee a customer's ability to purchase interruptible standby service. Also, it appears that if a customer purchases Non-Reserved Service for a scheduled outage, the customer pays the demand charges on the supplemental rate as opposed to the daily maintenance service demand charges contained in the SSR.
- **Inadequate flexibility.** EAI's standby tariff does not provide the standby customer with adequate flexibility to meet its standby requirements through alternative means such as self-dispatch, competitive market purchases, or special contracts.

Possible remedies for these issues are set forth below.

Potential Modifications to Standby Tariff

Following are suggested modifications to EAI's SSR tariff:

1. **The SSR reservation demand charge should be unbundled into generation, transmission, and distribution components.** The SSR tariff bundles these cost components into one reservation demand charge, making it difficult to assess the level of generation, transmission, and distribution costs that a standby customer is paying through the reservation charge. Unbundling these cost components would make the reservation charge more transparent. In addition, unbundling these costs would allow EAI to better reflect load diversity in the design of the demand charges for shared distribution and transmission facilities, as further discussed in recommendation number 9.
2. **The unbundled generation component of the reservation demand charge for standby service should be set such that it is equivalent to the best FOR exhibited by any generating unit on EAI's system.** This standby generation charge can be calculated by multiplying this best FOR by the demand charge in the customer's otherwise applicable full-requirements tariff.
3. **The reservation demand charge should be differentiated by season.** Currently the reservation demand charge is a flat $/kW-month for the entire year. However, all of the demand charges on supplemental rate schedules LGS and LPS are seasonal. The energy charges in the SSR are also seasonal. Thus, introducing seasonality into the design of the reservation demand charge would ensure consistency with the design of other rate components in EAI's tariff. This rate design modification would also more accurately reflect the seasonal variations in EAI's cost of service.
4. **The daily maintenance and backup demand charges should apply only during on-peak periods.** The SSR tariff defines on-peak hours for the Summer Period as 1 p.m. to 8 p.m. Monday through Friday. For the Other Period, on-peak hours are 7 a.m. to 6 p.m. Monday through Friday. The SSR tariff should be modified to specify that backup and maintenance demand charges would apply only during these on-peak hours. This would send an appropriate price signal to customers that would discourage them from imposing demands on EAI's system during times when EAI's generation reserve margins are at their tightest levels. Also, from a maintenance standpoint, customers can more effectively schedule their unit maintenance outages when demand charges are only imposed during the on-peak periods. (Of course, customers must notify EAI of any maintenance outage in advance.) Furthermore, demand charges that reflect time of use would be consistent with the requirement that maintenance service in the Summer Period be taken only during off-peak hours.

5. **The daily backup and maintenance energy charges should be further differentiated on a time-of-use basis.** In addition to the existing seasonal variation in these energy charges, the standby tariff should separate backup and maintenance energy charges for on-peak and off-peak hours. This modification would ensure that backup and maintenance energy charges more closely track EAI's incremental cost to provide energy to standby customers.
6. **Customer-generators should have the option to buy backup power from the market through the utility and thereby avoid the monthly reservation charge for standby generation service.** Under this approach, the standby customer would purchase backup energy from the utility only on an as-needed basis. Such purchases would be priced at the real time locational market price applicable to the geographic location at which the customer takes service. In addition, the customer would pay a share of any contracted capacity purchased, an allocated portion of transmission costs and ancillary services, and a small administrative fee to cover the utility's procurement cost.
7. **Customer-generators should have the option to provide the utility with a load reduction plan that demonstrates their ability to reduce a specified amount of load within a required timeframe to mitigate all or a portion of backup demand charges.** This approach would establish the standby customer's generation reservation demand charge as a function of the load that the utility would be required to meet through standby service. This standby service amount would be less than the rated output of the customer's self-generating unit because it would incorporate an adjustment for the amount of load reduction that the customer can achieve. This option would give the standby customer the flexibility to use demand response to meet all or a portion of its standby needs. The utility would retain the discretion to approve each standby customer's load reduction plan, including whether the customer can shed load with a sufficient response time that would allow the utility to avoid generation reserve costs in accordance with the utility's applicable reliability criteria.
8. **The Non-Reserved Service feature of the SSR tariff should be modified to facilitate the provision of interruptible standby service.** EAI essentially offers a full interruptible option through the Non Reserved Service provisions of the SSR. However, this service does not guarantee the provision of standby energy to support a maintenance outage. Even if such an outage is scheduled, the customer is required to pay significantly higher demand charges than would be incurred for a traditional maintenance outage under the tariff. The Non-Reserved Service provisions should be modified to include reasonable charges for maintenance outages and a requirement that such outages be scheduled at a mutually agreeable time for EAI and the customer.
9. **Standby charges for shared transmission and distribution facilities should reflect the load diversity of CHP customers.** The rates for shared transmission and distribution facilities, such as substations and primary feeders, should reflect load diversity. Load diversity recognizes that, except for facilities dedicated to a specific customer, the transmission and distribution system is not specifically designed to meet a single customer's needs, but is instead designed to serve the coincident peak demand by a pool of customers. Load diversity can be recognized by designing transmission and distribution demand charges on a coincident peak demand basis or by assessing charges for shared transmission and distribution facilities based on the demand established by the standby customer only during on-peak hours.
10. **Standby rate design should avoid demand ratchets.** Demand ratchets should not apply to EAI's charges to standby customers for shared distribution facilities. Instead, customer-generators should pay for non-dedicated distribution facilities only when they are actually purchasing backup or maintenance power in a particular month.
11. **Standby tariffs should be concise and easily understandable.** Customers who may consider installing a cogeneration system will have a difficult time understanding all of the charges that they may pay under various circumstances with the standby tariff and riders that EAI has in place today. For example, the maintenance service provision of the SSR tariff requires that maintenance outages during the summer season be performed only during the off-peak period. However, the tariff also states that maintenance service during the summer months will not be scheduled for a continuous period of less than one day. The latter provision essentially requires the customer to perform maintenance

during the on-peak hours of the summer months, creating an internal conflict in the maintenance service provisions of the tariff.

12. **Standby tariffs should specify the circumstances under which special contracts may be warranted.** Customers who have specific needs or operating conditions may require special contracts for standby power. EAI's standby tariffs should therefore contain provisions that would allow standby customers who demonstrate unique requirements to negotiate customer-specific standby service contracts with the utility. These customer specific contracts would be submitted to the Arkansas Public Service Commission for review and approval, subject to appropriate confidentiality restrictions that may be required to protect the customer's commercially sensitive information.

Economic Analysis of Standby Tariff

An economic analysis was performed to estimate the monthly costs incurred by EAI customers who have on-site generation under the SSR tariff. To calculate these costs, an economic model was developed that estimates the monthly costs for reservation, maintenance service, backup service, and supplemental power. See Attachment Arkansas 1 online for a detailed description of the model.

The economic analysis calculated costs for three customer load sizes with the following customer generation parameters:

1. **Small Load**
   a. Total Demand: 1,500 kW at 70-percent load factor
   b. Customer Generation Demand: 700 kW at 100-percent load factor
   c. Forced Outage Hours: 146
   d. Maintenance Hours: 73
   e. Supplemental Service on Rate Schedule LGS at Primary Voltage
2. **Medium Load**
   a. Total Demand: 6,000 kW at 80-percent load factor
   b. Customer Generation Demand: 4,000 kW at 100-percent load factor
   c. Forced Outage Hours: 73
   d. Maintenance Hours: 73
   e. Supplemental Service on Schedule LGS at primary voltage
3. **Large Load**
   a. Total Demand: 30,000 kW at 75-percent load factor
   b. Customer Generation Demand: 20,000 kW at 100-percent load factor
   c. Forced Outage (Backup Service) Hours: 37
   d. Maintenance Hours: 37
   e. Supplemental Service on Rate Schedule LPS at transmission voltage

Attachment Arkansas-2 summarizes SSR costs at the existing tariff rates for each representative customer using the BAI economic model. Note that a transmission-level customer could take service under Schedule LGS or Schedule LPS. BAI opted to model the transmission-level customer's costs assuming that service is taken under Schedule LPS, in order to ensure that both of EAI's supplemental service tariffs would be modeled in the study.

In addition, an economic analysis was performed to estimate the bill impacts of the suggested tariff improvements. The modeled tariff charges used to develop these bill impacts are not based on a formal original cost of service study. Rather, the authors relied on the charges in the current utility rate schedules, with adjustments based on the judgment of the study authors using the criteria appearing in the recommendations and Chapter 1. Following are the principal features of the modeled tariff charges:

1. A generation reservation charge was developed to reflect the performance of the best generating unit. For purposes of this analysis, the reservation charge was assumed to be five percent of the applicable generation and transmission demand charges, as the current SSR tariff charges are not unbundled.
2. A daily backup demand charge for power purchased during a forced outage was developed. If the self-generating unit was out of service for a full month, the charges would be equivalent to the applicable full requirements tariff.
3. The daily maintenance demand charges were set at 50 percent of the backup charges. The maintenance costs represent a discount from the daily backup demand charges because maintenance outages must be pre-scheduled with the utility during time periods when the utility's marginal cost of service is low. The current SSR maintenance daily demand charges are approximately 44 percent of the current daily backup demand charges. Therefore, this assumption is consistent with the SSR tariff.
4. The distribution rates were adjusted to reflect load diversity. The distribution component of the reservation charge was adjusted to include only an estimate of costs associated with dedicated distribution facilities. The non-dedicated

distribution costs were recovered through the daily demand charges described earlier. Because the current charges are bundled and no distinct distribution charges are available, the distribution component of the reservation charge was estimated by the study authors.

Attachment Arkansas 3 compares the charges/rates and costs that would be incurred under the existing standby tariff charges relative to the modified charges. The calculations in this attachment exclude all energy-related costs associated with purchases of fuel and supplemental power. With the exception of the VAR, the calculations also exclude costs associated with utility riders because they represent a small portion of the total cost of providing service to the customer, and none of the standby tariff modifications proposed in this study affect the excluded riders. The VAR was used to develop separate primary and transmission charges.

As Attachment Arkansas-3 shows, adjustments made to the reservation charges in the SSR tariff and the various supplemental rates to reflect the performance of the best self-generating unit on the utility system and load diversity result in reduced charges for the three load scenarios studied. The revised reservation charges are estimates; they were not developed from any cost of service study. Because rates are not unbundled, the authors used their judgment to estimate a breakdown of the generation, transmission, and distribution components of the reservation charges.

Adjustments also were made to reflect the recommendation to apply backup and maintenance charges only to demands that occur during on-peak weekday hours. As a result, the cost of providing standby service must be recovered over an approximate 20-day period as opposed to a 30 day period, increasing the per-unit charge relative to the current SSR tariff. Backup and maintenance charges were further adjusted to recognize load diversity and to capture transmission and distribution costs that are not recovered through the modified reservation charge.

An analysis was performed showing customer savings for the Summer Period resulting from taking both backup and maintenance service only during the *off*-peak period. These savings result from applying backup and maintenance demand charges only during on-peak hours.

Customers who impose demands for backup or maintenance service during on-peak periods will incur higher costs under our simulation of modified SSR charges. This is because the backup and maintenance charges must be increased relative to the current tariff charges to reflect the fact that cost recovery will occur only during the on-peak period.

Our analysis does not reflect savings and costs associated with implementing our recommended time-of-day energy prices. The results would have been similar to the results discussed earlier for time of day demand charges. That is, energy usage during the off-peak periods would produce savings, while on-peak energy usage would increase costs.

It is important to note that customers taking standby service on an interruptible basis would avoid both the utility's standby reservation charges and backup charges associated with any unscheduled outages. (The customer would still be required to pay for any dedicated distribution facilities.) However, the customer would default to the full-requirements tariff, and pay the generation, transmission, and distribution charges in that tariff, if the customer is unable to interrupt its load in compliance with the standby tariff conditions. For example, a transmission customer would pay all of the charges in EAI's LPS tariff.

Chapter 4. Colorado

Standby Rates for Customers of Public Service Company of Colorado

Description of Standby Rates

Public Service of Colorado (PSCo) provides Transmission Standby Service under Schedule TST and Primary Standby Service under Schedule PST. The tariffs are for commercial and industrial customers who operate generating equipment in parallel with the utility's electric system and require 10 kW or more of standby capacity service.

Standby service charges include monthly reservation fees, including a Service and Facility Charge, an Interconnection Charge, a Generation and Transmission Standby Capacity Reservation Fee, and a Distribution Standby Capacity Fee. In addition, the standby tariffs include a usage charge for demand and energy. The demand charge is only applicable after the customer has used the allowed Grace Energy Hours for standby service, set at 1,051 hours.

The customer's standby contract capacity is set forth in a standby service agreement. The quantity of standby capacity can be set at different levels for the summer and winter seasons.

For customers who have a standby contract capacity ranging from 10 to 10,000 kW, maintenance on the generating unit must occur during the calendar months of April, May, October, or November. Customers must provide PSCo with written notice of scheduled maintenance prior to the beginning of the maintenance period.

Customers who have a standby contract capacity greater than 10,000 kW must provide to the utility an annual projection of scheduled maintenance. PSCo must authorize the schedule in advance. The amount of advance notice that the customer must provide depends on the expected duration of the maintenance outage. For example, if a customer requests an outage longer than 30 days, the required notice is 90 days. Maintenance outages cannot exceed six weeks in any 12-month period. Qualified scheduled maintenance time does not count against the customer's Grace Energy Hours.

Description of Rate Components

Schedules TST and PST contain the following rate components:

1. A monthly Reservation Fee consisting of a Service Charge and a Facilities Charge;
2. An Interconnection Charge (only applicable to Schedule TST);
3. A Generation and Transmission Standby Capacity Reservation Fee; and
4. A Distribution Standby Capacity Fee (only applicable to Schedule PST).

For Schedule TST, the Service and Facilities Charge and Interconnection Charge are customer specific. In the case of Schedule PST, the Service and Facilities Charge is fixed for all customers at $305 per month, and no Interconnection Charge applies.

The Generation and Transmission Standby Capacity Fee covers capacity costs up to the allowed Grace Energy Hours for standby service (1,051 hours), assuming a 100-percent capacity factor for the customer's generating unit, for an annual period that begins October 1. The annual Grace Energy consumed by the customer under the tariff is equal to the customer's standby service hours multiplied by the customer's standby contract capacity. If the customer exceeds the annual allowed Grace Energy Hours, the customer is billed for any used capacity related to a forced outage of its generating unit at a demand charge that is approximately equivalent to the demand charge the customer would pay on the applicable supplemental (full-requirements) tariff. The standby tariffs also include an energy usage charge.

Assessment of PSCo's Standby Rates

PSCo's standby tariffs lack adequate price signals that could provide incentives to standby customers to improve the operation of their generating units or to make more efficient use of local utility resources. For example, the tariffs do not incorporate daily generation demand charges that would give standby customers an incentive to reduce the duration of their generating unit outages.

The generation reservation charges also lack time-of-use price signals that would encourage customers to shift their use of the utility's resources to off-peak periods.

In addition, the design of PSCo's standby charges fails to recognize load diversity, resulting in rates that send inaccurate price signals to customers regarding the cost drivers behind the utility's investments. Furthermore, PSCo's standby rates lack price transparency because the generation and transmission costs are bundled together in the Reservation Fee component of the tariff.

Finally, PSCo's tariffs do not provide the standby customer with adequate flexibility to meet its standby requirements through alternative means such as self-dispatch and the purchase of market-priced power.

Possible remedies for these issues are set forth below.

Potential Modifications to PSCo's Standby Tariffs

Following are suggested modifications to PSCo's standby tariffs for consideration:

1. **The monthly standby charge (Reservation Fee for Generation and Transmission Capacity) should be set such that it is equivalent to the best FOR exhibited by any generating unit on PSCo's system.** This standby generation charge can be calculated by multiplying this best FOR by the demand charge in the customer's otherwise applicable full requirements tariff. For example, the Summer period demand charge in Schedule TG for a transmission voltage level customer is $9.68 per kW. Multiplying this charge by a FOR of five percent produces a Generation and Transmission Reservation Fee of $0.484 per kW for the summer months.
2. **Daily standby generation demand charges should be assessed to provide incentives to improve the performance of self-generating units.** In addition to the Generation and Transmission Capacity Reservation Fee, standby customers should pay daily demand charges when they actually take backup power from the utility. To calculate a daily demand charge, divide the demand charge specified in the appropriate full-requirements tariff, adjusted to exclude the standby portion, by the average number of billing days in a month. Under this rate structure, the customer would pay the same amount as the supplemental rate if the customer took backup service for the entire month. The standby customer also would pay the utility's applicable fuel charges as well as all other applicable riders.
3. **Customer-generators should have the option to buy backup power from the utility at market prices and thereby avoid monthly reservation charges for standby service.** Under this approach, the standby customer would purchase backup energy from the utility on an as needed basis at wholesale market prices. In addition to these energy costs, the customer would pay a share of any capacity costs, an allocated portion of transmission costs and ancillary services, and a small administrative fee to cover the utility's costs for procurement.
4. **Customer-generators should have the option to provide the utility with a load reduction plan that demonstrates their ability to reduce a specified amount of load (kW) within a required timeframe to mitigate all or a portion of backup demand charges.** This approach would establish the standby customer's Reservation Fee as a function of the load that the utility would be required to meet through standby service. This standby service amount would be less than the rated output of the customer's generating unit because it would incorporate an adjustment for the amount of load reduction that the customer can achieve. This option would give the standby customer the flexibility to use demand response to meet all or a portion of its needs. The utility would retain the discretion to approve each customer's load reduction plan, including whether the customer can shed load with a sufficient response time to allow the utility to avoid generation reserve costs in accordance with applicable reliability criteria.
5. **The generation and transmission cost components of the Reservation Fee should be unbundled.** Under PSCo's current standby rate structure, it is difficult to assess the level of generation charges and transmission charges that a standby customer is paying in the Reservation Fee. This problem exists in both the standby tariffs and the supplemental tariff. Unbundling the generation and transmission cost components would make the rate design of the Reservation Fee more transparent.
6. **Standby charges for shared distribution facilities should reflect load diversity.** Customers should pay for the cost of distribution facilities that are dedicated entirely to serve an individual customer through the Reservation Fee. However, charges for shared distribution facilities such as substations and primary feeders should

reflect load diversity. Load diversity recognizes that a given portion of the distribution system is not specifically designed to meet a single customer's needs, but is instead designed to serve the coincident peak demand for distribution services that is established by a pool of customers. Load diversity can be recognized by designing the distribution demand charges on a coincident peak demand basis.

7. **Standby backup demand charges for generation and distribution service should apply only during on-peak hours.** This rate design would provide standby customers with an incentive to shift their use of the utility's assets to off-peak hours, when the cost of providing service is typically much lower. If PSCo's capacity costs are driven by customer demands established during defined on-peak periods, those same time periods should be used to establish the timeframe during which standby demand charges would be applicable.

Economic Analysis of Standby Tariffs

An economic analysis was performed to estimate the monthly costs incurred by PSCo customers who have on-site generation under Schedules PST and TST. To calculate these costs, an economic model was developed that estimates the monthly costs for reservation and supplemental power. Attachment Colorado 1, available online, describes the model in detail.

The economic analysis calculated costs for three load sizes and the following customer generation parameters:

1. **Small Load**
   a. Total Demand: 1,500 kW at 70-percent load factor
   b. Customer Generation Demand: 700 kW at 100-percent load factor
   c. Outage Hours: 40
   d. Supplemental Service on Schedule PG at primary voltage
2. **Medium Load**
   a. Total Demand: 6,000 kW at 80-percent load factor
   b. Customer Generation Demand: 4,000 kW at 100-percent load factor
   c. Outage Hours: 50
   d. Supplemental Service on Schedule PG at primary voltage
3. **Large Load**
   a. Total Demand: 30,000 kW at 75-percent load factor
   b. Customer Generation Demand: 20,000 kW at 100-percent load factor
   c. Outage Hours: 40
   d. Supplemental Service on Schedule TG at transmission voltage

Attachment Colorado-2 summarizes Schedule PST and TST costs at the existing tariff rates for each scenario using the BAI economic model.

In addition, BAI performed an economic analysis to estimate the bill impacts of the suggested tariff improvements. It should be noted that the modeled tariff charges used to develop these bill impacts are not based on a formal original cost of service study. Rather, the rate assumptions used in the economic model were developed by relying on the charges found in the current utility rate schedules, with appropriate adjustments based on the judgment of the study authors. The principal features of the modeled tariff charges include the following:

1. A generation reservation charge was developed to reflect the performance of the best generating unit. For purposes of this analysis, the reservation charge was assumed to be five percent of the applicable generation and transmission demand charges.
2. A daily backup demand charge for power purchased during a forced outage was developed. If the self-generating unit was out of service for a full month, the cost would be equivalent to the cost incurred on the otherwise applicable full requirements tariff.
3. The distribution rates were adjusted to reflect load diversity. The distribution component of the reservation charge was adjusted to include only an estimate of costs associated with dedicated distribution facilities. The non-dedicated distribution costs were recovered through the daily demand charges described earlier. Because the current charges are bundled and no distinct distribution charges are available, the distribution component of the reservation charge was estimated by the study authors.

Attachment Colorado 3 compares the charges/rates and costs that would be incurred under the existing standby tariff charges relative to the modified charges. The calculations exclude all costs associated with purchases of supplemental power. The calculations also exclude costs associated with all utility riders because none of the standby tariff modifications proposed in this study affect charges in the riders.

The adjustments to reservation charges to reflect the performance of the best self-generating unit on the utility's system and to reflect load diversity result in reduced reservation charges for the load scenarios studied. The revised reservation charges are estimates; they were not developed from a cost-of-service study. Daily demand charges were created and modeled for each day where the model simulates a forced outage. Consistent with the current tariff, scheduled maintenance outages do not trigger demand charges.

In addition, the Grace Energy Hours provision was eliminated. The customer would simply incur daily demand charges for each day associated with an unscheduled outage.

The study authors did not have the data required to develop on-peak demand charges. Assuming that the utility's capacity needs and costs are driven by defined on-peak periods, demand charges should be applied only during on-peak periods.

Page 3 of Attachment Colorado-3 graphically compares the cost associated with PSCo's current standby tariffs and the costs associated with the suggested revisions. The Primary Service scenario is applicable for Schedule PST and the Transmission Service scenario is applicable for Schedule TST. The attachment includes the assumptions used to develop the graphs.

Customers taking standby service on an interruptible basis would avoid both the standby reservation charges and backup charges associated with any unscheduled outages. (The customer would still be required to pay for any dedicated distribution facilities.) However, the customer would default to the full-requirements tariff, and pay the generation, transmission, and distribution charges in that tariff, if the customer is unable to interrupt its load in compliance with the standby tariff conditions.

Chapter 5. New Jersey

Standby Rates for Customers of Jersey Central Power & Light

Description of Standby Rates

Jersey Central Power & Light offers a Standby Service Rider (STB) that is available to customers who have their own generating equipment. Rider STB is not available in any month in which the availability of the customer's generating unit does not exceed 50 percent. Rider STB is an abbreviated, but complex, standby tariff. The rider consists of a single Standby Demand Charge to recover the cost of distribution service provided by Jersey Central. The formula for the charge contains two equations, and the customer's monthly bill is based on whichever equation produces the greatest charge.

The first equation of the Standby Demand Charge is the sum of two charges:

Part A: The Demand Rate (DR) per kW of the applicable service classification times the Billing Demand (BD) plus

Part B: The Standby Rate (SR) per kW times the lesser of either the Maximum Monthly (MM) on-peak load of the facility or the annual Average Generation (AG) during the on-peak time periods

Part A of the equation reflects the cost of distribution service for supplemental power. BD is determined by subtracting AG on-peak from the customer's MM on-peak load of the facility. However, BD is never allowed to be less than zero. Consequently, if the customer's generation provides *less* than the facility's total load requirement (i.e., AG < MM), the BD represents the supplemental load necessary to serve the facility, priced at the applicable supplemental service demand charge. However, if the customer's generation is *greater* than what the facility requires (i.e., AG > MM), the BD is zero. In the latter situation, no supplemental service demand charge is assessed because the customer's own generation can supply 100 percent of the customer's load requirements.

Part B of the equation reflects the cost of distribution service for standby service and is based on the lesser of MM on-peak load or AG. Thus, if the customer's own generation is less than the facility's total load requirement, the standby rate is assessed on the basis of AG. On the other hand, if the customer's generation capacity exceeds the facility's load requirements, the standby rate is assessed only on the customer's total on-peak load (MM).

The sum of the Part A and Part B charges is then compared to the results of the second equation of the Standby Demand Charge formula. The second equation is simply the Rider STB standby rate per kW times the Contract Demand (CD). The CD is the lesser of (1) the Capacity Rating of the generation facility, or (2) the greater of the MM facility on-peak load or the highest MM facility on-peak load during the most recent 12 months. For example, if the customer's own generation capacity is less than its MM facility on-peak load, this second equation will assess the standby charge based on the capacity rating of the generator. Alternatively, if the customer's generation is greater than what the facility requires, the standby rate is assessed based on the highest on-peak load of the facility over the most recent 12-month period.

A critical component of Rider STB is the determination of AG during on-peak times. Each month, AG is calculated and the most recent 12 months of AG are averaged for use in the monthly bill. To calculate the monthly AG, the customer's energy production during on-peak hours is divided by 260 hours (the full number of on-peak hours in each month) less any scheduled maintenance hours. However, the tariff provides that the scheduling of maintenance hours is permitted only for customers receiving service under Rider STB as of February 25, 1993.

The other caveat of Rider STB is that a customer's generating unit must have a FOR of less than 50 percent in order for the Rider to be available to the customer. If the customer's generation has an unscheduled outage that reduces its on-peak availability below 50 percent for the month, the customer's load for the month is served under the otherwise applicable full-requirements service classification.

Assessment of Standby Rates

A general concern with Jersey Central's standby rates is that the rate design may be too complex. Simplicity and ease of understanding are commonly recognized as appropriate rate design goals.

Also, the generator availability factor limitation is restrictive. Similarly, the standby tariff appears to impose undue constraints on the ability of customers to schedule maintenance outages of their generating units. Easing these restrictions would make it easier for customers to install and operate on-site generation.

Possible remedies for these issues are set forth below.

Potential Modifications to Standby Tariff

Following are suggested modifications to Jersey Central's standby tariffs for consideration:

1. **Scheduled maintenance hours should be allowed for all standby customers.** Under the current Rider STB, it appears that customers who commenced service under the rider after February 25, 1993 are not allowed to schedule maintenance for their generating units. The ability to schedule maintenance outages is critical for on-site generation.
2. **Standby service should be available to all self-generating customers regardless of the availability factor of their generating units.** Under the terms of Rider STB, any customer whose generation availability does not exceed 50 percent would default to the full requirements service tariff. The distribution demand charges in the full requirements tariffs are higher than the distribution charges in Rider STB. A more reasonable approach would be to structure Rider STB in a manner that gradually increases the cost of standby service as a standby customer's generation availability declines below 50 percent. Under this approach, the Rider STB demand charge would equal the full-requirements service demand charge only when the availability factor of the customer's generation unit fell to zero.
3. **Standby tariffs should be concise and easily understandable.** Customers who may consider installing on-site generation systems could have a difficult time understanding the different types of demand measurements that could affect the level of charges that they would pay under the STB Rider. The tariff could be simplified by imposing a set standby demand charge that assumes 100-percent availability of a customer's self-generating unit, accompanied by a daily demand charge that would recover the cost of backup distribution capacity purchased by the standby customer during forced outages and scheduled maintenance.
4. **Standby charges for shared distribution facilities should reflect load diversity.** The existing Rider STB voltage-level charges are likely below cost of service. The Rider STB voltage level charges are substantially less than the voltage level charges in the full requirements service tariffs. The difference in these rates indicates that the distribution charges for Rider STB were developed to encourage self-generation.

Economic Analysis of Standby Tariffs

An economic analysis was performed to estimate the monthly costs incurred by Jersey Central customers who have on-site generation under Rider STB. To calculate these costs, BAI developed an economic model that estimates the monthly costs for distribution energy charges, riders, and standby charges for Rider STB and the applicable service classifications (supplemental service). Attachment New Jersey 1, available online, describes the model in detail.

The model calculated costs for three load sizes and the following customer generation parameters:

1. **Small Load**
   a. Total Demand: 1,500 kW at 70-percent load factor
   b. Customer Generation Demand: 700 kW at 90-percent generator availability
   c. Maintenance Hours: 50
   d. Supplemental Service on Rate Schedule GP at primary voltage

2. **Medium Load**
   a. Total Demand: 6,000 kW at 80-percent load factor
   b. Customer Generation Demand: 4,000 kW at 85-percent generator availability
   c. Maintenance Hours: 60
   d. Supplemental Service on Schedule GT at high transmission voltage

3. Large Load

a. Total Demand: 30,000 kW at 75-percent load factor
b. Customer Generation Demand: 20,000 kW at 90-percent generator availability
c. Maintenance Hours: 30
d. Supplemental Service on Rate Schedule GT at transmission voltage

Attachment New Jersey-2 summarizes Rider STB costs at the existing tariff rates for each representative customer using BAI's economic model. The economic model did not include costs for generation service. Generation service for these customers is typically supplied by a third-party supplier, and including any cost estimate was deemed to be not necessary and speculative by the authors.

In addition, an economic analysis was performed to estimate the bill impacts of the suggested tariff improvements described earlier. Modeled tariff charges used to develop these bill impacts are not based on a formal cost of service study. Rather, the rate assumptions used in the economic model were developed by relying on the charges in the current utility rate schedules, with adjustments based on the judgment of the study authors. The principal feature of the modeled tariff charge is making Rider STB available to all self-generating customers regardless of the availability of the generating unit in any month.

Attachment New Jersey 3 compares costs that would be incurred under the existing standby tariff charges compared to the modified charges. The calculations exclude costs associated with all other utility riders. None of the standby tariff modifications proposed in this study affects the excluded riders.

Chapter 6. Ohio

Standby Rates for Customers of AEP Ohio

Description of Standby Rates

AEP Ohio operates as Ohio Power Company in the state of Ohio. The utility has two rate zones: the Columbus Southern Power rate zone and the Ohio Power rate zone. Each of these rate zones has a standby tariff, Schedule SBS (Standby Service), applicable to customers who purchase power from Ohio Power Company. In addition, each rate zone has an open access standby tariff, Schedule OAD-SBS (Open Access Distribution Standby Service), which applies to customers who purchase power from a third-party supplier.

The standby tariff schedules and associated riders in each of the rate zones are identical except for the level of the charges. In addition, the terms and conditions for the provision of distribution service are the same for both Schedule SBS and Schedule OAD SBS. As a result, it is only necessary to address the terms and conditions of the tariffs for a single rate zone.

It is anticipated that by the end of 2015 all AEP Ohio Power Company customers will be able to choose a Certified Retail Electric Service (CRES) provider. Schedule OAD-SBS will apply to distribution-only customers who take service from a CRES provider. Schedule SBS will apply to distribution and Standard Service Offer (SSO) customers – those who do not take service from a CRES provider. SSO customers will pay energy prices based on the results of a competitive bidding process (an energy-only auction).

Schedule SBS – Standby Power Supplied by Ohio Power Company

Schedule SBS is available to customers who have an on-site source of electric energy supply and a standby generation supply requirement of 50,000 kW or less. The standby contract capacity in kW is initially established by mutual agreement between the customer and the utility.

The standby customer pays a demand charge for generation that is a function of the FOR and the supply voltage. The utility offers a choice of six specified FORs (5, 10, 15, 20, 25, and 30 percent), with higher outage rates corresponding to higher generation demand charges. The customer can purchase backup power for a designated number of hours per year. The number of hours for which backup power is purchased varies as a function of the outage rate that the customer selects. If the customer requires backup power in excess of the designated hours during the control year, the customer defaults to the applicable full service tariff for the rest of the contract period.

For example, a primary voltage customer in the Columbus Southern Power Rate Zone who estimates a FOR of 15 percent will pay a monthly generation charge of $2.455/kW,[14] regardless of whether the customer actually buys backup power. The monthly generation charge allows the customer to buy back up energy for up to 1,314 hours (15 percent of 8,760 hours) during the year. When the customer exceeds the allowed outage hours, the customer is billed under the appropriate supplemental rate schedule. In that instance the monthly generation demand charge increases significantly and can become $9.662/kW[15] (Schedule GS-3, Primary Voltage).

In addition to the generation charges discussed earlier, the customer pays a monthly distribution standby charge that is a function of the customer's voltage level of service. The distribution charge is assessed on a $/kW basis and recovers secondary and primary voltage level distribution costs. The distribution charges are not a function of the FOR and are the same for each FOR by voltage level (secondary and primary).

14 Tariff rate in place at the time of BAI's economic analysis. In September 2012, the charge increased to $2.671/kW.

15 The charge increased to $10.511/kW in September 2012.

Subtransmission and transmission costs that are incurred to serve standby customers are recovered through a Transmission Cost Recovery Rider. This rider allows the customer to purchase subtransmission/transmission service for a set number of hours based on the selected FOR. The rider rate design is structured in the same manner as the generation demand charges described previously.

In the Columbus Southern Power Rate Zone, generation and transmission charges are the same for sub transmission and transmission customers. In the Ohio Power Rate Zone, there are separate generation charges for sub transmission and transmission customers, but the transmission rider charges are the same for both voltage levels.

Schedule OAD-SBS – Power Supplied by a Third Party

Schedule OAD-SBS is available to customers who have an on-site source of electric energy supply and a standby distribution requirement of 50,000 kW or less. The standby contract capacity in kW is initially established by mutual agreement between the customer and the utility.

Under this tariff schedule, the customer pays the monthly distribution standby charge that is applicable to Schedule SBS customers (described previously). Schedule OAD-SBS customers taking transmission service do so under the terms and conditions of the applicable open access transmission tariff (OATT), as filed with and accepted by the Federal Energy Regulatory Commission (FERC).

Assessment of Standby Rates

A central concern with AEP Ohio's standby rates is the design of the generation and transmission demand charges. Specifically the demand charge, with its menu of FORs, is complex and places substantial risk on the standby customer to accurately forecast its generating unit outage rate. The risk to the customer is created primarily by the fact that under forecasting the actual unit outage rate can lead to a substantial cost penalty when the customer is billed under the applicable supplemental rate schedule. At the same time, over forecasting actual unit performance forces the customer to pay generation and transmission demand charges in excess of the amount actually required to back up the customer's generating unit in a given year.

AEP Ohio's standby tariffs also lack adequate price signals that could provide incentives to standby customers to improve the operation of their own generating units or to make more efficient use of local utility resources. For example, the tariffs do not incorporate daily generation demand charges that would give standby customers an incentive to reduce the duration of their generating unit outages. In addition, the generation demand charges and fuel charges lack time-of-use price signals that would encourage customers to shift their use of the utility's resources to off-peak periods that exhibit a lower marginal cost of service.

Furthermore, the standby charges for the use of AEP Ohio's shared distribution facilities fail to recognize load diversity.

Finally, AEP Ohio's standby tariffs do not provide the standby customer with adequate flexibility to meet its standby requirements through alternative means such as self-dispatch, competitive market purchases, or special contracts.

Possible remedies for these issues are set forth below.

Potential Modifications to Standby Tariffs

Following are suggested modifications to AEP Ohio's standby tariffs for consideration:

1. **For customers who take standby generation service from the utility, the monthly backup charge (reservation demand charge) for standby generation service should be set such that it is equivalent to the best FOR exhibited by any generating unit on AEP Ohio's system.** This standby generation charge can be calculated by multiplying the best FOR by the demand charge in the customer's otherwise applicable full-requirements tariff. For example, using the demand charge in the Columbus Southern Power rate zone, General Service Medium Load Factor (Schedule GS 3) rate schedule, and an assumed FOR of 5 percent produces a monthly generation reservation charge of \$0.483/kW (0.05 x \$9.662/kW).[16]
2. **Daily standby generation demand charges should be assessed to provide incentives to improve the performance of self-generating units.** In addition to the reservation demand charge discussed previously, standby customers should pay daily demand charges when they actually take backup power from the utility. The daily demand charge is the demand charge as specified in the

16 In September 2012, the generation demand charges for Columbus Southern Power Rate Zone were modified as follows: Schedule GS-3 (secondary voltage) - \$10.867/kW, Schedule GS-3 (primary voltage) - \$10.511/kW.

appropriate full-service tariff adjusted to exclude the standby portion, divided by the average number of billing days in a month. When purchasing maintenance power, the daily demand charges should be reduced to reflect the scheduling of maintenance power when costs and systems stresses are low. The standby customer also should pay the utility's applicable fuel and purchased power charges as well as all other applicable riders.

3. **Customer-generators should have the option to buy backup power from the market through the utility and thereby avoid the monthly reservation charge for standby generation service.** Under this alternative approach, the standby customer would purchase backup energy from the utility only on an as-needed basis. Such purchases would be priced at the real time locational market price applicable to the geographic location at which the customer takes service. In addition, the customer would pay a share of any contracted capacity purchased, an allocated portion of transmission costs and ancillary services, and a small administrative fee to cover the utility's procurement cost if the power is purchased through the utility.
4. **Customer-generators should have the option to provide the utility with a load reduction plan that demonstrates their ability to reduce a specified kW amount of load within a required timeframe to mitigate all or a portion of backup demand charges.** This alternative approach would establish the standby customer's generation reservation demand charge as a function of the load that the local utility would be required to meet through standby service. This standby service amount would be less than the rated output of the customer's self-generating unit because it would incorporate an adjustment for the amount of load reduction that the customer can achieve. This option would give the standby customer the flexibility to use demand response to meet all or a portion of its needs. The local utility would retain the discretion to approve each standby customer's load reduction plan, including whether the customer can shed load with a sufficient response time that would allow the utility to avoid generation reserve costs in accordance with the utility's applicable reliability criteria. This assumes that the utility is providing the backup service.
5. **Standby charges for shared distribution facilities should reflect the load diversity of CHP customers.** Under AEP Ohio's tariffs today, customer generators taking secondary or primary voltage level service pay the same distribution charges as full-requirements customers. This rate design is appropriate for distribution facilities dedicated entirely to serving the standby customer. However, charges for shared distribution facilities, such as substations and primary feeders, should reflect load diversity. Load diversity recognizes that a given portion of the distribution system is not specifically designed to meet a single customer's needs, but is instead designed to serve the coincident peak demand for distribution services that is established by a pool of customers. Load diversity can be recognized by designing the distribution demand charges on a coincident peak demand basis or by assessing charges for shared distribution facilities based on the demand established by the standby customer only during on-peak hours, as discussed below.

   It should be noted that Ohio Power Company currently appears to reflect load diversity in its transmission service charges for standby customers. Specifically the customer generator pays for transmission service provided by the utility based on the selected FOR of the customer's generating unit.
6. **Standby demand charges for generation and distribution service should apply only during on-peak hours.** Ohio Power Company currently offers optional time-of-day schedules that assess demand charges based only on the peak demand established by the customer during on-peak hours. This provision could be applied to the determination of standby generation and distribution demand charges as well. This rate design would provide standby customers with an incentive to shift their use of the utility's assets to off-peak hours, when the marginal cost of providing service is typically much lower.
7. **Standby rate design should avoid demand ratchets.** For example, no demand ratchets should apply to AEP Ohio's charges to standby customers for shared distribution facilities. Instead customer-generators should pay for non-dedicated distribution facilities only when they are actually purchasing backup or maintenance power in a particular month. Any demand that a customer

generator imposes on the utility system in a given month should not be used to establish that customer's distribution or other demand charges for future months.

8. **Standby tariffs should be concise and easily understandable.** Customers who may consider installing a cogeneration system will have a difficult time understanding all of the charges they may pay under various circumstances with the standby tariffs and riders that AEP Ohio has in place today. To reduce the complexity of the standby tariffs, the Public Utilities Commission of Ohio may wish to consider replacing the existing menu of standby generation demand charges linked to various FOR levels with a single generation standby demand charge that is designed as a function of the best FOR among generating units on the utility's system.
9. **Fuel and purchased power charges for standby customers should vary by time of use.** Standby customers have some flexibility in the scheduling of maintenance outages of their generating units. If a customer purchases maintenance power, the economic choice may be to schedule such outages during time periods when the utility's incremental cost of fuel is low. By sending a price signal that more accurately reflects the utility's marginal fuel cost, time-of-use fuel charges can assist standby customers in efficiently scheduling maintenance outages of their generating units at times that would minimize the utility's cost of providing standby (maintenance) energy. The potential benefits of time-of-use fuel charges also would apply to full service customers who are capable of shifting load to low-cost periods.
10. **Standby tariffs should specify the circumstances under which special contracts may be warranted.** Customers who have standby power requirements in excess of 50,000 kW, as well as standby customers who have specific needs or operating conditions, may require special contracts for standby power. AEP Ohio's standby tariffs should therefore contain provisions that would allow standby customers who demonstrate unique requirements to negotiate customer-specific standby service contracts with the utility. These customer-specific contracts would be submitted to the Public Utilities Commission for review and approval, subject to appropriate confidentiality restrictions that may be required to protect the customer's commercially sensitive information.

Economic Analysis of Standby Tariffs

An economic analysis was performed to estimate the monthly costs incurred by Ohio Power Company customers who have on-site generation for both Schedule SBS and Schedule OAD SBS. To calculate these costs, an economic model was developed that estimates the monthly costs for standby, maintenance service, backup service, and supplemental power. Attachment Ohio-1, available online, describes the model in detail.

The economic analysis calculated costs for three load sizes for both the Columbus Southern rate zone and the Ohio Power rate zone. Following are the load sizes and customer generation parameters analyzed:

1. **Small Load**
   a. Total Demand: 1,500 kW at 70-percent load factor
   b. Customer Generation Demand: 700 kW at 100-percent load factor
   c. Forced Outage Hours: 146
   d. Maintenance Hours: 73
   e. Supplemental Service on Schedule GS-3 at Primary Voltage
2. **Medium Load**
   a. Total Demand: 6,000 kW at 80-percent load factor
   b. Customer Generation Demand: 4,000 kW at 100-percent load factor
   c. Forced Outage Hours: 73
   d. Maintenance Hours: 73
   e. Supplemental Service on Schedule GS-3 at Primary Voltage
3. **Large Load**
   a. Total Demand: 30,000 kW at 75-percent load factor
   b. Customer Generation Demand: 20,000 kW at 100-percent load factor
   c. Forced Outage (Backup Service) Hours: 37
   d. Maintenance Hours: 37
   e. Supplemental Service on Schedule GS-4 at Transmission Voltage for the Columbus Southern rate zone and Schedule GS-3 for the Ohio Power rate zone

Attachment Ohio-2 summarizes costs at the existing tariffs for each rate zone. A comparison should not be made between the full service costs and the open access costs, because the market energy costs used for the open access tariff analysis do not incorporate all of the cost components that a customer may actually incur. BAI used historic market prices to simulate the cost of competitive market purchases.

In addition, an economic analysis was performed to estimate the bill impacts of the suggested tariff improvements described previously. Modeled tariff charges used to develop these bill impacts are not based on a formal cost-of-service study. Rather, the rate assumptions used in the economic model were developed by relying on the charges found in the current utility rate schedules and the transmission rider, with appropriate adjustments based on the judgment of the study authors. The modeled tariff charges included the following:

1. A generation reservation charge was developed to reflect the performance of the best generating unit on the utility's system. The reservation charge was assumed to be five percent of the applicable generation demand charge as specified in an appropriate supplemental tariff. Because we propose a uniform reservation charge for all customer generators, the model does not select a forecasted FOR.
2. A daily backup demand charge for power purchased during forced outages was developed by prorating the generation demand charge in the full-requirements tariff. If the self-generating unit was out of service for a full month, the charges would be equivalent to the applicable full service tariff.
3. The daily maintenance demand charges were set at 50 percent of the backup charges. The maintenance costs represent a discount from the daily backup demand charges because maintenance outages must be prescheduled with the utility during periods when the utility's marginal cost of service is low. A 50-percent discount factor was therefore applied to the backup charges to recognize the lower cost of service associated with maintenance power.
4. The distribution rates were adjusted to reflect load diversity. First, the distribution reservation charge was adjusted to include only the costs associated with dedicated distribution facilities. The non-dedicated distribution costs were recovered through the daily demand charges described earlier. Second, the standby distribution reservation charges contained in the standby tariffs for each rate zone were reduced by 20 percent to estimate the dedicated distribution charge.

Attachment Ohio-3 compares the charges/rates and costs that would be incurred under the existing standby tariff charges and the proposed modifications. For Schedule SBS, only changes in standby tariff and transmission charges are shown. The calculations exclude all energy-related costs associated with purchases of fuel, supplemental power, and power purchased from competitive electricity suppliers. With the exception of the transmission rider, the calculations also exclude costs associated with all utility riders. These rider costs were excluded from the analysis because they represent a small portion of the total cost of providing service to the customer. Moreover, none of the standby tariff modifications proposed in this study affects these rider charges.

Attachment Ohio-3, page 1, shows the results of the economic analysis for the Columbus Southern rate zone for Schedule SBS. Page 2 of the same attachment shows the results of the economic analysis for rate Schedule SBS for the Ohio Power rate zone.

The analysis for both of the rate zones indicates a slight reduction in cost for the suggested modifications for small load and medium load customers. The economic analysis for the large load indicates an increase in the cost associated with the modifications to Schedule SBS.

However, the small and medium load economic analyses model a worst-case scenario. That is, for each FOR, the maximum backup energy and arguably the maximum number of backup days were selected.

For example, for the small load the model assumes that the customer selected a FOR of 20 percent under the existing standby tariff rate design. This assumption implies that backup power would be needed for seven days [(730 hours x 20%) / 24] and the amount of backup energy would be 102,200 kWh (700 kW x 730 x 20%). This reflects the maximum amount of backup energy required and likely the maximum backup days. It is highly unlikely that a customer would pick a FOR assuming charges for the maximum amount of backup hours and backup energy. Of note, if the customer exceeds during the year the maximum specified hours for backup power, the customer will default to the supplemental rate. For the small load example, this would increase the generation charge to approximately $9.662 per kW. This is an increase from the $3.171 per kW that the customer is currently paying.

In addition, by defaulting to the supplemental rate, the transmission cost would increase from $0.50 per kW to $2.005 per kW. Because of the significant penalties involved, it is highly likely that the customer would over-forecast the FOR for its generating unit.

This is significant because the analysis shows that under the current Schedule SBS the customer incurs the bulk of its charges through standby demand charges that the customer must pay each month, regardless of actual use of standby service. However, when the tariff schedule is modified to incorporate the rate changes recommended in this study, a significant portion of the charges are incurred through the daily demand charges, which are assessed only when backup or maintenance power is actually purchased by the customer.

For the large load customer, the analysis is affected by the selected FOR under the existing standby tariff charges. Had a higher FOR such as 20 percent been selected, the economic analysis would have indicated that the tariff modifications proposed in this study would result in lower costs to the customer. Finally, it should be noted that Schedule SBS may cease to exist by the end of 2015, as Ohio Power Company is expected to transition to full open access at that time.

In addition to the economic analysis for Schedule SBS discussed earlier, the study also provides an analysis that compares the economic impact of the current Schedule OAD-SBS tariffs to the tariff charges that would result from the rate modifications proposed in this study. In this instance, only the distribution charge changes. For Schedule OAD SBS, the only suggested revision is to reflect load diversity in the distribution reservation demand charges. As discussed earlier in this chapter, this rate modification is appropriate because the distribution reservation demand charges should only reflect the cost of those facilities that are dedicated to serve the customer. As was the case in the analysis of the Schedule SBS rates, this tariff modification was reflected in the tariff charges by reducing the distribution costs by 20 percent. This adjusted portion of the distribution costs was then added to the daily demand charge that is paid when the customer purchases backup or maintenance power.

Under Schedule OAD-SBS, the customer purchases maintenance power not from Ohio Power Company but through a third-party supplier. This largely eliminates the utility cost savings that could be realized by scheduling maintenance power during off-peak periods. For this reason, the study assumes that the charges for backup and maintenance distribution service would be identical under this schedule.

Attachment Ohio-4 shows that the tariff modifications proposed in this study would result in lower Schedule OAD-SBS costs in each of the rate zones for both the small and medium loads. The large load customer would incur no distribution costs because it is assumed that this customer purchases power at a transmission voltage level delivery point. The large customer would be securing standby generation from the competitive market and procuring transmission service under the applicable FERC OATT. Consequently the tariff modifications proposed in this study would have no impact on the cost of standby service for the large customer.

It is important to note that customers taking standby service on an interruptible basis would avoid both the utility's standby reservation charges and backup charges associated with any unscheduled outages. (The customer would still be required to pay for any dedicated distribution facilities.) However, the customer would default to the full-requirements tariff, and pay the generation, transmission, and distribution charges in that tariff, if the customer is unable to interrupt its load in compliance with the standby tariff conditions.

Chapter 7. Utah

Standby Rates for Customers of Rocky Mountain Power

Description of Standby Rates

Rocky Mountain Power (RMP) offers standby service on Schedule 31 to customers who use their own generating equipment on a regular basis. Total backup and maintenance power taken by the customer under Schedule 31 cannot exceed 10,000 kW. The schedule contains rates, terms, and conditions for the provision of backup power, maintenance power, and excess power:

1. ***Backup power*** is the electric energy and capacity supplied by RMP during an unscheduled outage of the customer's electric generating equipment. The backup demand is measured only during the on-peak hours, 7 a.m. to 11 p.m. Monday through Friday, except designated holidays and days when generator maintenance is scheduled. All energy is priced under the provisions of the applicable general service schedule.
2. ***Maintenance power*** is the electric energy and capacity supplied by RMP during scheduled outages of the customer's generating equipment. For customers who have a peak demand in excess of 1,000 kW, the customer must submit a proposed maintenance schedule for each month of an 18-month period. The customer can schedule maintenance for a maximum of 30 days per year. The 30 days may be taken in either one continuous period or two continuous 15-day periods.
3. ***Excess power*** is the power that RMP supplies to the customer in excess of the total contract demand. The total contract demand is defined as the sum of the supplementary contract demand and the backup contract demand. Supplemental power is billed and priced pursuant to the provisions of the applicable general service schedule.

Description of Rate Components

Schedule 31 contains four charges that vary by voltage level (secondary, primary, and transmission):

1. Monthly customer charges
2. Facilities charges
3. Daily on-peak backup power charges – the daily maintenance power charges are set at one-half of the backup power on-peak charges
4. Excess power charges

Schedule 31 does not contain a generation reservation charge. The facilities charges apply to the kW of backup contract demand and are designed to recover the cost of distribution and transmission facilities.

The backup power charges apply only during the on-peak time periods designated in Schedule 31. No backup power charges are assessed to customers during off-peak hours. All backup and maintenance energy used by the customer is billed under the pricing provisions of the applicable general service schedule.

The excess power charges in Schedule 31 are set at approximately $40 per kW for primary and transmission voltage customers. The excess power charges apply only to demand that exceeds the total contract demand. These charges are intended to provide customers with an incentive to accurately designate their backup contract demand and supplemental power demand.

Description of Rider Schedule 33

RMP also offers Generation Replacement Service (Schedule 33). Schedule 33 is available to customers who wish to curtail on-site generation and receive replacement power and energy from RMP. RMP offers the customer terms and conditions associated with the provision of generation replacement service at least five days in advance. The customer must respond to RMP's offer within 48 hours. If the offer is accepted, the customer then contracts for a specific amount of replacement power and energy at a designated price for the offer period. The customer must pay for the contracted amount of replacement power regardless of the customer's actual use of replacement service.

Assessment of Standby Rates

Schedule 31 facilities charges do not recognize load diversity in the use of RMP's shared transmission and distribution facilities.

In addition, Schedule 31 does not provide the standby customer with adequate flexibility to meet its standby requirements through alternative means such as self-dispatch, market-priced power purchases for backup power, or special contracts.

Potential Modifications to Standby Tariff

Following are suggested modifications to RMP's standby tariffs for consideration:

1. **The on-peak, backup power charges should be stated on a seasonal basis.** Although energy charges for supplemental-service rate schedules differentiate power charges for the summer and non-summer periods, backup power charges do not. The backup power charges should reflect higher rates during the summer period and lower rates during the non-summer period consistent with the supplemental power rates.
2. **Customer-generators should have the option to buy backup power from the utility at market prices and thereby avoid the backup charge for standby generation service.** Under this approach, the standby customer would purchase backup capacity and energy from the utility only on an as-needed basis. Such purchases would be priced at market prices at the appropriate trading hub. In addition, the customer would pay a share of any transmission and ancillary services costs, as well as a small administrative fee to cover the utility's procurement cost.

   RMP's Energy Exchange Program Rider (Schedule 71) provides payments to participating customers at market-based prices for voluntarily reducing electricity consumption when called upon by the utility. The same data source for these hourly market prices could be used to price backup and maintenance energy under a market supply option for standby service.
3. **Customer-generators should have the option to provide the utility with a load reduction plan that demonstrates their ability to reduce a specified amount of load (kW) within a required timeframe to mitigate all, or a portion of, backup demand charges.** This approach would establish the standby customer's backup demand as a function of the load that the local utility would be required to meet through standby service. The standby service amount would be less than the rated output of the customer's self-generating unit because it would incorporate an adjustment for the amount of load reduction the customer can achieve. This option would give the standby customer the flexibility to use demand response to meet all, or a portion of, its needs. The utility would retain the discretion to approve each standby customer's load reduction plan, including whether the customer can shed load with a sufficient response time that would allow the utility to avoid generation costs in accordance with applicable reliability criteria.
4. **Standby demand charges for shared transmission and distribution facilities should reflect the load diversity.** The rates for shared transmission and distribution facilities, such as substations and primary feeders, should reflect load diversity. Load diversity recognizes that the transmission and a portion of the distribution systems are not specifically designed to meet a single customer's needs but are instead designed to serve the coincident peak demand for transmission and distribution services established by a pool of customers.
5. **The cap for the provision of backup and maintenance service should be raised.** RMP's Schedule 31 restricts the provision of backup and maintenance power to loads that do not exceed 10,000 kW. A load cap may be needed to address concerns regarding the adequacy of the utility's generation reserves. However, the level of the cap is low and therefore unnecessarily restrictive.
6. **Standby tariffs should specify the circumstances under which special contracts may be warranted.** Customers who have specific needs or operating conditions may require special contracts for standby power. For example, RMP should be required to negotiate a special contract for the provision of standby service with any customer whose backup generation requirement exceeds the designated cap. RMP's standby tariffs should contain provisions that would allow standby customers who demonstrate unique requirements to negotiate customer-specific standby service contracts with the utility. These customer-specific contracts would be submitted to the Public Service Commission for review and approval, subject to appropriate confidentiality restrictions that may be required to protect the customer's commercially sensitive information.

7. **The customer should be able to use the 30-day allotment of maintenance power over more than two instances per year.** Schedule 31 allows the standby customer to take maintenance power either in one continuous 30-day period or two continuous 15-day periods. Allowing more flexibility on the number of times a customer can take maintenance power would provide more opportunities to address generator reliability issues.

Economic Analysis of Potential Modifications

BAI performed an economic analysis to estimate the monthly costs incurred by RMP customers who have on-site generation under Schedule 31. BAI developed an economic model that estimates the monthly costs for reservation, maintenance service, backup service, and supplemental power. Attachment Utah 1, available online, describes the model results in detail.

The economic analysis calculated costs for three load sizes with the following customer generation parameters:

1. Small Load

a. Total Demand: 4,350 kW at 75-percent load factor
b. Customer Generation Demand: 1,950 kW at 100-percent load factor
c. Forced Outage Hours: 48
d. Maintenance Hours: 72
e. Supplemental Service on Schedule Large General Service (Schedule 8) at Primary Voltage

2. Medium Load

a. Total Demand: 19,500 kW at 80-percent load factor
b. Customer Generation Demand: 7,500 kW at 100-percent load factor
c. Forced Outage Hours: 48
d. Maintenance Hours: 36
e. Supplemental Service on Schedule General Service – High Voltage (Schedule 9) at Transmission Voltage

3. Large Load

a. Total Demand: 25,000 kW at 80-percent load factor
b. Customer Generation Demand: 25,000 kW at 80-percent load factor
c. Forced Outage (Backup Service) Hours: 48
d. Maintenance Hours: 48
e. Supplemental Service on Schedule General Service – High Voltage (Schedule 9) at Transmission Voltage

Attachment Utah-2 summarizes Schedule 31 costs at the existing tariff rates for each representative load based on the output of the economic model.

In addition, BAI performed an economic analysis to estimate the bill impacts of the suggested tariff improvements described earlier in this chapter. Modeled tariff charges used to develop these bill impacts are not based on a formal cost of service study. Rather, the rate assumptions used in the economic model were developed based on charges in the current utility rate schedules, with adjustments based on the judgment of the study authors. The principal features of the modeled tariff charges include the following:

1. The on-peak backup power charges are stated on a seasonal basis, consistent with the power charges in the supplemental rate schedules.
2. A generation reservation charge was developed to reflect the performance of the best generating unit on the utility's system. For purposes of this analysis, the reservation charge was assumed to be five percent of the applicable generation and transmission demand charges.
3. The distribution rates were adjusted to reflect load diversity. The distribution component of the reservation charge was adjusted to include only an estimate of costs associated with dedicated distribution facilities. The non-dedicated distribution costs were recovered through the daily demand charges described earlier. Because the current charges are bundled and no distinct distribution charges are available, the distribution component of the reservation charge was estimated by the study authors.
4. The daily maintenance demand charges were set at 50 percent of the backup charges. The maintenance costs represent a discount from the daily backup demand charges because maintenance outages must be pre-scheduled with the utility during time periods when the utility's marginal cost of service is low.

Attachment Utah 3 compares the charges/rates and costs that would be incurred under the existing standby tariff charges and the modified charges. Page 1 of the attachment shows the current and proposed facilities and backup power charges for primary and transmission voltage customers. The calculations used to develop the graphs on page 2 of the attachment exclude all energy-related supplemental power and rider costs.

As shown on Attachment Utah-3, BAI developed a backup power reservation charge to reflect the estimated performance of the best self-generating unit on the utility's system, and the facilities charges were revised to reflect load diversity. The charges are estimates and were not developed from a cost-of-service study.

Page 2 of Attachment Utah-3 shows that the creation of seasonal backup power charges result in higher costs during the summer months and lower costs in the winter months. In addition, the revised charges are lower because of the reduction to the facilities charges to reflect load diversity for shared transmission and distribution facilities.

It is important to note that customers taking standby service on an interruptible basis would avoid both the utility's standby reservation charges and backup charges associated with any unscheduled outages. (The customer would still be required to pay for any dedicated distribution facilities.) However, the customer would default to the full-requirements tariff, and pay the generation, transmission, and distribution charges in that tariff, if the customer is unable to interrupt its load in compliance with the standby tariff conditions.

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Attachments

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Attachment Arkansas-2
Costs at Existing Standby Rates

Attachment Arkansas-3
Cost Comparison of Existing Rates and Modified Rates

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The Regulatory Assistance Project (RAP) is a global, non-profit team of experts focused on the long-term economic and environmental sustainability of the power and natural gas sectors. We provide technical and policy assistance on regulatory and market policies that promote economic efficiency, environmental protection, system reliability, and the fair allocation of system benefits among consumers. We work extensively in the US, China, the European Union, and India.
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Conservation Applied Research & Development (CARD) Program

FINAL REPORT

MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Analysis of Standby Rates and Net Metering Policy Effects on Combined Heat and Power (CHP) Opportunities in Minnesota

Prepared for: Minnesota Department of Commerce, Division of Energy Resources
Prepared by: Energy Resources Center

ERC
ENERGY RESOURCES CENTER

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Acronyms

DG	Distributed Generation
CEAC	US DOE Midwest Clean Energy Application Center
CHP	Combined Heat and Power
COMM	Minnesota Department of Commerce, Division of Energy Resources
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
ERC	Energy Resources Center
FOR	Forced Outage Rate
IOU	Investor Owned Utilities
IREC	Interstate Renewable Energy Council
kW	Kilowatt
kWh	Kilowatt-hour
MPUC	Minnesota Public Utility Commission
MW	Megawatt
NG	Natural Gas
NM	Net Metering
NEG	Net Excess Generation
UIC	University of Illinois at Chicago
WHP	Waste Heat to Power

Executive Summary

The Energy Resources Center (ERC), located at the University of Illinois at Chicago (UIC) conducted the research for this paper for the State of Minnesota Department of Commerce, Division of Energy Resources under CARD Grant #59974. The goal of this project was to analyze the effects of Minnesota's existing net metering rules and standby rates on combined heat and power (CHP) and waste heat to power (WHP) applications, to identify possible modifications to these rates and to analyze the benefits of identified policy modifications.

Utility Energy Efficiency Programs that offer direct grants and incentives to encourage investment in traditional energy efficiency measures are effective in moving the market in the short term; however, sound energy policies are also crucial to promote long term, sustainable energy efficiency. This paper examines the energy policies of standby rates and net metering and their impact on CHP development in Minnesota. Specifically, this paper:

1. Assesses the existing standby rates and net metering policies and how they affect the market acceptance of CHP projects today and presents recommendations that could help reduce the barriers that these factors impose on CHP development in Minnesota.

2. Models the economic potential of CHP projects in Minnesota investor owned utility (IOU) service territories based on analyzing the impact of current versus hypothetically improved standby rates.

When CHP systems are properly sized and installed, they can reduce energy costs, improve power reliability, improve power quality, increase energy efficiency, and improve environmental quality. Significant potential exists in Minnesota for CHP projects today, but as this report explores, barriers such as standby rates may be preventing some of this potential growth.

Standby Rate Analysis and Recommendations

Standby rates in Minnesota have been perceived as a significant barrier to CHP development. Standby service comprises the set of retail electric rates for customers with on-site, non-emergency, distributed generation (including CHP). This paper used two different methodologies to evaluate Minnesota standby rates in order to more comprehensively understand the barriers within each rate structure.

The first approach used three criteria to evaluate the efficacy of standby rates: transparency, flexibility and promotion of efficient consumption. These three criteria represent overarching functional categories which have ascribed through utility rate theory as applied to cost of service regulations and realized through successful standby rates from utilities across the U.S. The definitions of each of these criteria are as follows:

- *Transparent rates* provide customers with clear signals on the cost of electric service and help customers operate in a cost-effective manner that lessens their burden to the utility.

- *Flexible rates* are those which allow the customer to avoid charges when not using service.

- Electric rates that promote *economically efficient consumption* should be designed to discourage the wasteful use of utility services while promoting all that is economically justified in terms of private and social costs incurred and benefits received.

The second approach assesses the financial impact created by standby rates through an analytic framework using the avoided rate as the primary metric for evaluating the barriers within standby rates.[1] The concept evaluates the financial impacts of standby rates on DG systems by comparing the aggregate per-kilowatt hour (kWh) cost of full requirements customers (that is, customers with no on-site generation) to that of standby customers. The avoided rate is the aggregate per unit price of electricity not purchased from the utility due to on-site generation. This rate is then compared to the aggregate per unit price of electricity purchased before the installation of a CHP system. The avoided rate percentages used in this paper reflect the extent to which the avoided rate (on a per unit basis) matches the full-requirements rate. An avoided rate of 100% means that the value of a kWh purchased will remain the same when not purchased.

Although the standby recommendations for each utility are somewhat unique and are further explored in the full paper, Table 1 summarizes the most reoccurring standby modifications for IOUs in Minnesota grouped by functional criteria[2]:

Principle	Analysis and Recommendation
Transparency	*Standby rates should be transparent, concise and easily understandable.* Potential CHP customers should be able to accurately predict future standby charges in order to assess their financial impacts on CHP feasibility.
	Standby usage fees for both demand and energy should reflect time-of-use cost drivers. Time-of-use energy rates send clear price signals as to the cost for the utility to generate needed energy. This would further incentivize the use of off-peak standby services.
Flexibility	*The Forced Outage Rate should be used in the calculation of a customer's reservation charge.* The inclusion of a customer's forced outage rate directly incentivizes standby customers to limit their use of backup service. This further links the use of standby to the price paid to reserve such service creating a strong price signal for customers to run most efficiently. This would also involve the removal of the grace period.
	The standby demand usage fees should only apply during on-peak hours and be charged on a daily basis. This rate design would encourage DG customers to shift their use of standby service to off-peak periods when the marginal cost to provide service is generally much lower. Furthermore, this design would allow customers to save money by reducing the duration of outages.

[1] The guidelines and methodology regarding the concept of the avoided rate were presented by the U.S. EPA CHP Partnership in their 2009 paper titled, "Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs."
[2] See section 2 for an overview of standby rate concepts and component definitions.

Principle	Analysis and Recommendation
Economically Efficient Consumption	*Grace periods exempting demand usage fees should be removed where they exist and standby rates should be priced to reflect usage.* Exempting an arbitrary number of hours against demand usage charges sends inaccurate prices signals about the cost to provide this service. The monthly reservation cost providing the grace periods charges for 964 hours of usage no matter if a customer needs that level of service. Standby demand usage should be priced as-used on a daily and preferably an on-peak basis. This method directly ties the standby customer to the costs associated with proving standby service and allows customers to avoid monthly reservation charges by increasing reliability.

Table 1: Standby Rate Policy Recommendations

When evaluating standby rates using the avoided rate metric/analysis, the results shown in Table 2 range between 77% and 97%. In general, when analyzing the avoided rate metric, the closer the values are to 100% the lower the economic barrier standby rates impose on CHP projects. The IOUs of Xcel Energy, Minnesota Power and Otter Tail Power demonstrated rates 87% and greater while Alliant Energy modeled no avoided rates greater than 78%.

It should be noted that, though simple to calculate and communicate, the avoided rate metric is a blunt tool that may over simplify situations. The economic effect of standby rates is largely related to the specific attributes and operating schedules of a customer's generator. While the avoided rate can give a general overview of economic barriers, the actual effects on standby customers may vary greatly depending on actual circumstances. Because of the limitations in the avoided rate analysis, we also included the three criteria of transparency, flexibility and economic efficiency in the analysis of standby rates.

	Generating Capacity (kW)			
Standby Avoided Rates	**500**	**3,000**	**10,000**	**10,000**
Xcel Energy	87%	90%	93%	96%
Alliant Energy	77%	77%	78%	78%
Minnesota Power	90%	95%	92%	97%
Otter Tail Power	97%	96%	96%	97%

Table 2: Avoided Rates of Minnesota IOUs[3]

Net Metering Analysis and Recommendations

Net metering allows for the flow of electricity both to and from the customer – typically through a single, bi-directional meter – allowing qualified distributed generation customers to export electricity to the grid during times when their generation exceeds their on-site consumption.

The net metering rates updated through House File 729 (which increased the capacity limit from 40 kW to 1 MW for IOUs) are fundamentally in line with successful approaches used in other states as well as

[3] Further information on the modeling assumptions can be found in Section 2.4. Utility specific modeling inputs can be found in Sections 3.5 (Xcel), 4.5 (Alliant), 5.5 (Minnesota Power) and 6.5 (Otter Tail Power).

those approaches advocated by the Interstate Renewable Energy Council (IREC) and the Regulatory Assistance Project (RAP).[4] A possible impediment identified is that larger net metering customers (100 kW to 1 MW) might face standby charges. The inclusion of standby rates for the larger net metering customer base could essentially cap net metering at 100 kW since standby charges would increase acceptable payback windows for most clean distributed energy projects. Much like utilities are currently required to demonstrate, "the effects of net metering on the reliability of the electric system"[5] in order to implement a net metering aggregate capacity limit so should they be required to demonstrate inaccurate cost recovery through regular rate structures before implementing any standby rate on net metering customers. This report identifies 17 states that exempt standby charges for net metering customers. Table 3 summarizes the recommendations to the current net metering policies in Minnesota:

Recommendation	More Information
Standby rates should not be applied when utilities can recover capacity costs through regular rates.	Net Metering rates already include provisions to recuperate the full demand related costs from net metering customers. While net metering rates bill energy consumed or credit energy generated on a net basis they contain no such provision for calculating demand charges; like full-requirement rates, these rates bill customers for their maximum demand placed on the grid. However, not all net metering customers go offline the same amount for time. For those customers with little or infrequent downtime, standby rates might be an appropriate method to recover capacity related costs. In granting utilities the ability to impose standby charges on net metering customers above 100 kW, the Minnesota Public Utility Commission should be careful not to allow utilities to double charge for capacity cost recovery.
The Net Excess Generation Credit should be the average retail electric rate for all net metering customers.	All net metering customers should be treated equally and be provided the same Net Excess Generation Credit.

Table 3: Recommendations to Minnesota Net Metering Policies

Economic Potential Analysis

ERC worked in conjunction with ICF International in order to develop the overall economic potential analysis of CHP generating capacity within Minnesota IOU service territories (i.e. not including CHP systems installed within electric municipality and cooperative service territories). The ICF model analyzed the impact of standby rates on economic potential incorporating project simple payback rates. Simple paybacks were modeled using current utility electric prices, natural gas rate estimates based on average prices from the U.S. Energy Information Administration (EIA) for the commercial and industrial sector, and average CHP equipment cost and performance characteristics. Payback periods were grouped into three categories, 0-5 years, 5-10 years and above 10 years.

[4] Minnesota State Legislature, *House File 729 4th Engrossment*, 88th Legislature (2013-2014). Available at, https://www.revisor.mn.gov/bills/text.php?number=HF729&session_year=2013&session_number=0&version=latest

[5] Minnesota Statute §216B.164, Subd 4b (2013)

Within the four major investor owned utilities, there lies 1,798 MW of CHP technical potential. When modeling the base case and using current standby rates, results indicate 779 MW of new CHP project potential with a payback of 10 years or less. Table 4 provides a breakout of the economic potential in three payback periods.[6]

	Payback >10 years	Payback 5-10 years	Payback 0-5 years	Total Tech Potential, MW
Alliant	52	5	0	57
MN Power	95	141	0	236
Xcel Energy	809	633	0	1,442
Otter Tail	63	0	0	63
Total	1,019	779	0	1,798

Table 4: CHP Economic Potential per Utility (Base Case)

When the avoided rates were increased in the model from their current standing to a hypothetical value of 100%, the overall CHP generating capacity with paybacks of 10 years or less increased by 43% from 779 MW to 1,116 MW, as shown in Table 5. Factoring in that some of the IOUs already have relatively reasonable avoided rate metrics of 87% and greater, it should be noted that even a small increase in improving standby rates can have a significant impact on the payback periods of CHP projects in Minnesota.

	Payback >10	Payback 5-10 years	Payback 0-5 years	Total Tech Potential, MW
Alliant	52	5	0	57
MN Power	95	141	0	236
Xcel Energy	479	964	0	1,442
Otter Tail	57	6	0	63
Total	682	1,116	0	1,798

Table 5: CHP Economic Potential per Utility (100% Avoided Rate)

Though there have been some recent improvements to standby rates in Minnesota (e.g. Xcel Energy), standby rates still remain as barriers to CHP development as noted in the modeling by ICF International. Hypothetically modifying the standby rates using the avoided rate metric resulted in a 43% increase in CHP projects moving from paybacks greater than 10 years to projects experiencing paybacks less than 10 years. This indicates opportunities for improvement within the existing standby rate structures can positively impact the overall economic potential of new CHP generating capacity within Minnesota.

[6] Economic potential rests on a continuum involving market acceptance curves that vary between every economic sector and individual business. This definition of economic potential isn't intended to imply that all included capacity is viable but that viable and likely projects form a smaller subset within economic potential.

1. Introduction

The Energy Resources Center, located at the University of Illinois at Chicago (ERC) conducted the research for this paper for the State of Minnesota Department of Commerce, Division of Energy Resources under CARD Grant #59974. The goal of this project was to analyze the effects of Minnesota's existing net metering rules and standby rates on combined heat and power (CHP) and waste heat to power (WHP) applications, to identify possible modifications to these rates and to analyze the benefits of identified policy modifications.

Under current Minnesota law, utilities must achieve annual energy savings equal to at least 1.5% of annual retail energy sales. While Utility Energy Efficiency Programs that offer direct grants and incentives to encourage investment in traditional energy efficiency measures are very effective in moving the market in the short term, sound energy policies are crucial for long term, sustainable energy efficiency. This paper addresses two Minnesota energy policies, *standby rates* and *net metering*, and analyzes them to determine whether or not they present barriers to the overall economic potential of distributed generation (DG) technologies, specifically CHP.

A CHP system is a form of DG that generates at least a portion of the electricity requirements of a building, facility, and/or campus while recycling the thermal energy that would typically be exhausted from the electric generation process. This thermal energy can provide space heating/cooling, process heating/cooling, dehumidification and/or increased electrical generation. CHP systems use commercially available state of the art technologies, and if properly sized and installed can:

- Reduce Energy Costs
- Improve Power Reliability
- Improve Power Quality
- Increase Energy Efficiency
- Improve Environmental Quality

CHP is all the more important when one examines the efficiency levels of large utility electric generators. On average, two-thirds of fuel used to generate electricity in the U.S. is wasted by venting unused thermal energy into the atmosphere or dissipating it through cooling systems. While there have been impressive energy efficiency gains in other sectors of the economy since the oil price shocks of the 1970's, the average efficiency of power generation within the U.S. has remained around 34% since

1960.[7] In comparison, CHP systems can operate at efficiency levels as high as 80%, helping to mitigate high energy costs and reduce air pollution.[8]

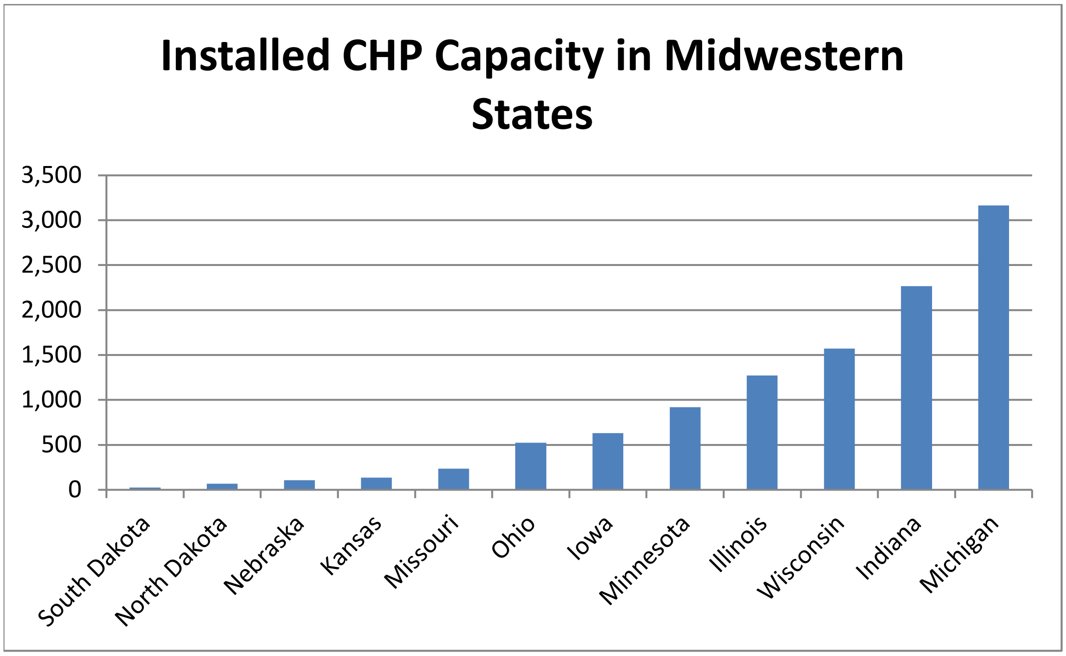

Figure 1: CHP Capacity in the Midwest, 2013. Source ICF International

Today, there is an installed CHP generating capacity base of 918 MW in the State of Minnesota, currently ranking 5th among the 12 Midwest states and representing 8.4% of the total CHP installed generating capacity in the 12 Midwest State Region (Figure 1).[9] The 918 MW are installed at 55 site locations and represent 8.0% of the state's utility generating capacity of 11,547 MW.[10] Our research estimates that there remains 1,975 MW of unrealized CHP technical potential in Minnesota. This CHP technical potential is an estimation of market size constrained only by technological limits – the ability of CHP technologies to meet potential end users' electric and thermal requirements – and represents the upper most bound for CHP capacity as technical potential does not consider capital costs, regulatory barriers, energy costs, avoided electric costs, or other factors impacting the economic feasibility of CHP systems. Although there represents a total technical potential of 1,975 MW of unrealized CHP in Minnesota, this paper will focus only on 1,798 MW of this potential – the potential within the four major investor owned utilities of Alliant Energy, Minnesota Power, Otter Tail Power, and Xcel Energy. The remaining potential is lies within the municipal and electric cooperatives.

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[7] Oak Ridge National Laboratory, *Combined Heat and Power: Effective Energy Solutions for a Sustainable Future*, by Anna Shipley et al, (Oak Ridge., 2008), 6.
[8] American Gas Association, *The Opportunity for CHP in the United States*, Prepared by ICF International, (May 2013), 1.
[9] DOE CHP Installation Database.
[10] U.S. Energy Information Administration, Office of Electricity, Renewables and Uranium Statistics, "State Electric Profiles 2012," 2012.

Installing 1,798 MW of unrealized CHP technical potential could lead to cleaner and more energy efficient generation, representing a significant opportunity for new CHP installations to contribute toward the annual utility energy savings goal of 1.5%.

In May 2013, Governor Mark Dayton signed House File 729 (HF 729) that contained provisions pertaining to economic development, housing, commerce, and energy bill. While the energy section of the bill was focused mostly on renewable technology like solar, Article 9 focused exclusively on distributed generation. Though there are still legal details in interpreting sections of the law to be ruled on by the Minnesota Public Utility Commission (MPUC), HF 729 undoubtedly reduces previous barriers to new CHP projects being developed.

The standby rate section is divided into five sections, the first to explain how standby rates function and the latter four to analyze each investor owned utility's (IOU) individual standby rate. Another section discusses net metering rates. Since IOUs in Minnesota have not yet had the requisite time to acquire MPUC approval for new net metering rates, this report only analyzes net metering as specified in HF 729. The final section presents the aggregate modeling results and analyzes the extent to which standby and net metering are barriers to CHP development. The paper analyzes these energy policies and economic potential for the four major IOUs of Xcel Energy (Northern States Power Company), Alliant Energy (Interstate Power and Light), Minnesota Power, and Otter Tail Power Company.

2. Standby Rates

Standby rates, otherwise known as partial service rates, constitute a subset of retail electric tariffs that are intended for customers with on-site, non-emergency distributed generation. They are the rates utilities charge an operator of distributed generation to provide backup electricity during both scheduled and unscheduled outages in addition to the cost to reserve such service. In contrast to standby rates, full-requirements rates are those paid by service customers whose sole source of electricity is the utility. To facilitate the understanding of standby rates this chapter is divided into four sections:

1) the first section (2.1) discusses the economics, structure, and regulatory environment surrounding electric rates;

2) the second section (2.2) provides definitions on key concepts in standby rate design;

3) the third section (2.3) presents successful approaches to standby rate construction including three criteria by which to judge the soundness and desirability of cost based standby rates, and;

4) the fourth section (2.4) details the analytic framework by which the economic effects of standby rates were analyzed.

2.1 Factors of Cost Based Electric Rate Regulation

Minnesota regulates their utilities using a cost of service methodology. Regulators often use the cost of service standard to calculate "fair and reasonable" rates because its methodology directly ties consumers to the cost of producing those goods and services consumed, in this case, electricity.[11] Furthermore, the Public Utility Regulatory Policies Act of 1978 (PURPA) mandates that electric rates shall be designed, to the maximum extent practicable, to reflect the cost of service.[12] The cost of service standard ties prices and price structures to the costs to render electric service to different classes of customers with the intention that one pays for the costs imposed on the system. Because electric utilities in regulated states, such as Minnesota, are natural monopolies, it is necessary for a state to regulate the electric market in order to protect the consumer. A cost based approach, like the cost of service standard achieves at least three important functions of public utility rate-making intended to stimulate competitive market conditions: *consumer rationing, capital attraction*, and *compensatory income transfer*.[13]

1) **Consumer Rationing** – Under the principle of *consumer rationing*, consumers are free to take service (whatever kinds in whatever amounts), "as long as they are ready to indemnify the

[11] David Moskovitz, *Profits and Progress Through Distributed Resources*, (Gardiner, ME: Regulatory Assistance Project, 2000), 3.
[12] *Public Utility Regulatory Policies*, 16 U.S.C. § 2625, (2012).
[13] James C. Bonbright, Albert L. Danielsen, and, David R. Kamerschen, *Principles of Public Utility Rates* (Arlington: Public Utilities Reports, 1988), 111.

producers…for the costs of rendition," thereby rationing themselves to only what is needed and no more.[14]

2) **Capital Attraction** – To ensure service now and in the future, *capital attraction* guarantees the service provider a funding source for both operating and capital expenses that are necessary to sustain grid infrastructure.

3) **Compensatory Income Transfer** – Lastly, the *compensatory income transfer* function requires those seeking a service to account for the use of the service through a monetary expenditure.

Achieving these three functions helps the cost of service standard recreate competitive market conditions in a situation devoid of competing market forces (i.e. electric utility monopoly in a regulated state or electric distribution utility in a deregulated state). Economists and rate theorists typically use competitive markets as guidelines for the regulation of monopolistic prices. The cost of service methodology is a commonly applied regulatory approach to simulate competitive market conditions.

2.1.1 General Rate Attributes

No matter the method in which rates are regulated (i.e. cost of service, value of service, performance standard, etc.), general rate function can be classified into three overarching attributes: revenue, cost, and practicality.[15]

1) **Revenue** related concerns include achieving the total revenue requirement predictably and stably through rates that are themselves stable and predictable.

2) **Cost** related concerns include promoting economically efficient consumption through portioning costs fairly among customers and avoiding discriminatory rates.

3) **Practical** concerns include attributes of payment collection, rate simplicity, and ease of understanding.

These attribute categories are important for shaping the context of the Minnesota standby rate analysis in this paper. Rates that fail to clearly display these attributes may also fail at achieving the larger rate functions mentioned above, which, in turn, could allow for claims of unfair or non-cost based rates. The cost attribute function is important in this discussion as it specifically addresses issues of fair cost allocation. Rates that do not fairly allocate costs might impede the consumer rationing function which in turn hinders a consumer's ability to ration consumption based on accurate and market-simulated pricing. When costs are not fairly recovered or when rates are not cost-based, utilities could manipulate prices in order to increase consumption and thus revenue. The role of a cost of service methodology is to bind customers and customer classes to the specific costs they impose on the utility.

[14] Ibid.
[15] Bonbright et al, 383.

2.1.2 Creating Cost Based Standby Rates

Cost-based rate structures must achieve both the rate attributes and rate functions listed previously while also allowing the utility to obtain its revenue requirements. A cost of service study is necessary in order to determine the various costs imposed on the utility by each customer class. The central questions often facing a cost of service study are:

1) What specific costs are included?

2) How are these costs recovered from customers based on their consumption patterns?

Utility customers are typically grouped into rate classes and charged based on how they consume electric service. The most common utility classes correspond to residential, commercial and industrial classifications; however other classifications using similar voltage level and/or load level are also used in creating customer classes. The use of aggregate classes allows the utility to create rates that more accurately allocate costs, yet challenges arise when determining the level at which some customer classes are responsible for utility costs, the example in this paper being standby customers.

Designing the needed generation, transmission and distribution capacity for full-requirements customers is straightforward. Shared infrastructure is sized to meet the coincident peak of customers on each specific distribution and transmission line.[16] Dedicated infrastructure is sized to meet a customer's non-coincident peak demand (or billing demand). Since the full-requirements customers purchase capacity from the utility on a regular schedule the sizing requirements are well understood. However, standby customers have unique load characteristics that differ from full-requirements customers adding additional complications.

The Oregon Public Utility Commission states that cost-based standby tariffs should, "be based on the actual costs of providing backup generation and grid capacity for distributed generators during their occasional outages, spread across the year and following random patterns."[17] Understanding that costs must be fairly accounted for, a fundamental issue in creating cost-based standby rates is determining the appropriate level of reserve capacity that a utility must carry to provide standby service to customers with on-site generation.

For example, reliable standby customers with high availability rates impose their full demand on the grid far less frequently and in shorter durations than a standard full-requirements customer (i.e. some only requiring backup service a handful of days a year). The effect is that a utility supplying standby power will not have to plan as much reserve capacity to serve self-generating customers as it does for full-

[16] Coincident peak demand refers to the demand imposed by the customer at the time of a utility system's maximum demand. Non-coincident peak demand is the customer's largest demand exerted on the grid regardless of time. Utilities build infrastructure to service coincident peak not the summation non-coincident customer peak loads. The only infrastructure that has no coincident peak is that dedicated solely for one customer.

[17] Oregon Public Utility Commission, *Distributed Generation in Oregon: Overview Regulatory Barriers and Recommendations,* Prepared by Lisa Schwartz, Oregon Public Utility Commission (2005), 22.

requirements customers.[18] This is because needed reserve capacity decreases as generator reliability increases such that those generators with lower than average forced outage rates (FOR) require less reserved capacity. Furthermore, since properly scheduled maintenance service falls largely in the off-peak period the amount of reserve capacity held for scheduled maintenance should be far less, if not zero, than that of backup service. As the Oregon PUC noted, an outage during off-peak periods does not impose the same cost on the utility system as an outage during peak demand and should therefore be priced differently.[19]

2.2 Definition of Key Concepts

Key concepts are delineated between full-requirements customers and those who require standby service. The following are rate design elements most common to full-requirements customers:[20] Customer Charges, Energy Charges, and Demand Charges.

2.2.1 Rate Design Elements of Full Requirements Customers

The Customer Charge is the monthly (or daily) fixed charge that is attributed to the costs of metering, drop wire, etc. This functions as a grid access fee to be paid whether or not service is taken.

The Energy Charges are those covering the consumption of the electricity commodity applied usually on a per kWh basis. These rates may be differentiated by time-of-use, season, or block depending on how the utility's costs are incurred.

The Demand Charges, used more for larger commercial and industrial customers, are based on a customer's peak electric demand and are generally intended to recover the capital costs of capacity necessary to meet peak loads (including both generation and transmission/distribution capacity). Because electric service is provided "on demand" the system must be designed to meet a variety of peak loads: those for the grid as a whole, those of customers served by individual parts of the grid network and those of individual customers. Demand charges are a means of allocating and recovering the fixed costs to provide the necessary capacity with which to serve customers at peak periods.

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[18] Regulatory Assistance Project, and Brubaker & Associates, Inc, *Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States,* prepared for Oak Ridge National Laboratory, (Montpelier, VT, 2014), 11.
[19] Oregon Public Utility Commission, 22.
[20] Environmental Protection Agency. Office of Atmospheric Programs. Climate Protection Partnerships Division. *Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs*, by the Regulatory Assistance Project and ICF International, (Washington, D.C., 2009), 3.

2.2.2 Rate Design Elements of Standby Customers

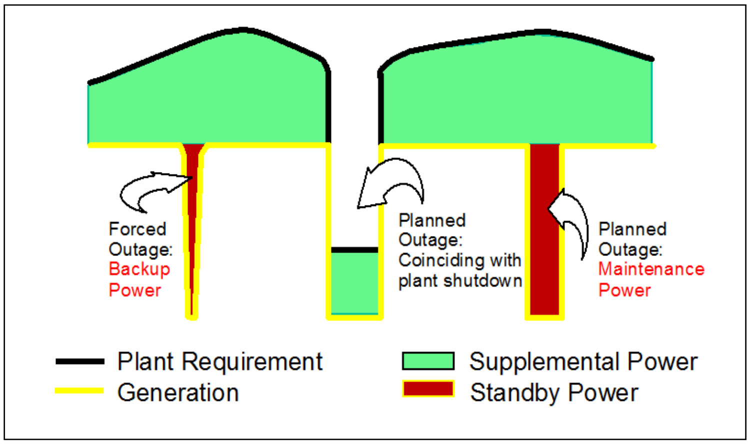

Figure 2: Illustration of Standby Customers Power Requirements. Source: Regulatory Assistance Project

Figure 2 depicts how standby functions with regards to planned and unplanned outages, supplemental service and the reservation charge. The yellow line represents the capacity of an on-site generator to which the standby reservation charge applies whereas the red blocks underneath the yellow line represent generator outages when standby service is required. These standby rate elements are further defined:

The Reservation Charge is a monthly charge per kW of the customer's needed standby capacity and cannot be avoided when standby is not taken. The reservation charge generally ensures that standby service will be available when needed by the customer during unscheduled and scheduled outages.

The Demand Ratchet is a mechanism by which the electric utility bills a customer for the maximum demand measured (or a percentage thereof) over the prior year or season. Ratchets are most commonly used to calculate the demand charges for full-requirements customers; however, they are sometimes applied to bills for the demand caused by an on-site generator outage. In Minnesota this occurs when Xcel or Alliant standby customers exceed 964 hours of unscheduled service. Under such a situation it is possible that a customer would pay both a demand charge and a standby reservation charge for the same capacity.

Backup Service is the capacity and energy supplied by the utility during an unscheduled outage of the on-site generator. Generally, the utility must receive a warning from the customer before the use of backup service so that they may ramp up generation if need be. The four Minnesota utilities included in this report use the monthly reservation charge ($/kW) related to the capacity of the on-site generator in order to cover the costs to reserve backup capacity instead of an as-used demand charge issued only during outages.

Scheduled Maintenance Service is the capacity and energy supplied by the utility when a customer's on-site generator is down for routine maintenance. Since this service is usually scheduled far in advance and can take place during nonpeak periods and seasons, it creates few additional capacity costs to the utility.

Supplemental Service provides for additional energy and capacity a customer might need beyond that generated on-site. In most cases this service is provided under the otherwise applicable full-requirements tariff.

The Grace Period is the allotted time a standby customer may use backup service without incurring any additional demand and/or usage charges. Both Xcel Energy and Minnesota Power provide 964 hours of backup service free of additional usage charges. The cost associated with providing the grace period is built into the reservation charge.

Forced Outage Rate (FOR) of a generating unit for a given time span is defined as the number of hours the unit is forced out of service for emergency reasons divided by the number of total hours that the generating unit is available for service during that time interval (plus the number of hours during a forced outage). The FOR measures the probability that the unit will not be available for service when required.[21]

Coincident Factor is the ratio of a customer's coincident peak demand to its non-coincident peak demand. A customer's coincident peak is the demand imposed during the utility system's maximum demand whereas the non-coincident peak is a customer's maximum demand recorded during any time. A customer having a higher coincidence factor will impose greater demand related costs per kW of non-coincident demand than a customer with a lower coincidence factor.

2.3 Successful Approaches in Standby Rate Design

While standby rates are necessary to recover the fully allocated embedded costs that the utility incurs to provide backup and maintenance service, they can also be created in such a way as to financially burden distributed generation customers unfairly thereby erecting barriers to DG development. The goal of well-crafted standby rates should promote economic efficiency, fairness, simplicity, transparency, and system reliability while penalizing those generators that incur large costs to the utility.[22] Rate structures should be created in a manner that avoids arbitrariness, capriciousness and undue discrimination while covering the full costs each customer and customer class imposes on the grid. No rate class should subsidize the costs incurred by other classes nor should customers pay for costs that they themselves do not incur. The following three criteria were created to evaluate the soundness and desirability of cost based standby rates structures:

[21] Regulatory Assistance Project, *Standby Rates for Combined Heat and Power*, 10.
[22] National Regulatory Research Institute, *Electric Utility Standby Rates: Updates for Today and Tomorrow,* Report 12-11, by Tom Stanton (July 2012), Page 10.

Criterion 1 – Transparency:

Rates should be easily understood and include rate mechanics and price levels that are stable and predictable. Transparent rates should provide price signals that clearly reflect the many cost drivers associated with electric service allowing customers to understand when, how and where utility costs are incurred. Having clearly delineated price signals and rate mechanics helps promote more accurate consumer rationing and addresses the revenue and practicality rate attributes. Aspects of transparency entail:

- The separation of capacity costs to best reflect the drivers of cost for each component, i.e. dedicated distribution, shared distribution, transmission, and generation capacity;
- A differentiated demand charge reflecting the costs associated with on-peak and off-peak periods for transmission and distribution service;
- Unbundling rates to the maximum extent feasible; and
- Clear, easily understood rate mechanics.

Examples of successful transparent rate design include:

- Pacific Power Partial Service Rate 47 (Oregon) separates the distribution charge into three categories (Basic, Facility, On-Peak) to most accurately capture the drivers of each component.[23] The facilities charge covers the cost of local delivery facilities that must be dedicated to serve a specific customer while the on-peak demand charge covers the costs associated with shared distribution facilities. The basic charge is akin to a customer charge – a fixed monthly charge delineated by voltage class.
- Detroit Edison Rider 3: Parallel Operation and Standby Service (Michigan) uses daily, as-used, on-peak demand charge to recover utility costs; these charges are differentiated depending on the nature of the service (scheduled or unscheduled).[24]
- MidAmerican Energy Rider SPS (Iowa) divides the reservation charge into four categories corresponding to generation, transmission, distribution and substation cost causation. A customer's forced outage rate is used to calculate the generation and transmission components.

Criterion 2 – Flexibility:

Rates should distribute the burden of meeting total revenue requirements fairly and without arbitrariness, capriciousness, and inequalities among the beneficiaries of service in order to avoid undue discrimination. Flexible rates should allow customers to avoid charges when not taking service and also provide standby customers with options for taking alternative service. Flexibility in electric rates helps

[23] Pacific Power, Schedule 47: Delivery Service, Sheet No. 47-1, Effective January 1, 2014
[24] The Detroit Edison Electric Company, Standard Contract Rider No. 3: Parallel Operation and Standby Service and Station Power Standby Service, Sheet No. D-70.00, Effective January 5, 2014

promote consumer rationing and addresses the cost and practicality rate attributes. Further aspects of flexibility include:

- Rates that provide the ability to self-supply reserves or remove load during DG outages;
- Rates that incorporate load diversity and outage probability;
- Rates that allow customers to minimize charges by operating in a manner beneficial for the utility; and
- Rates that allow, if available, the ability to purchase power from real-time markets.

Examples of successful flexible rate design include:

- Pacific Power (Oregon) allows customers to self-supply reserve load in order to avoid utility reserve charge.[25]
- Pacific Gas and Electric Schedule S (California) calculates reservation capacity using the outage diversity of a customer's generating unit.[26]
- American Electric Power (Ohio) allows a standby customer to choose their outage level which corresponds to the monthly reservation charge.[27]
- Detroit Edison (Michigan) allows standby customers the choice to purchase all standby capacity from the real time market.

Criterion 3 – Economically Efficient Consumption:

Rates should be designed to discourage the wasteful use of utility services while promoting all that is economically justified in terms of the private and social costs incurred and benefits received. Economically efficient rates incentivize customers to take service when service is least expensive. This rate criterion helps promote more accurate consumer rationing and addresses the cost and revenue rate attributes. Rate mechanisms that help achieve economically efficient consumption include:

- Sending clear price signals that charge a premium for unscheduled outage demand that coincides with utility peak, and minimizing charges for scheduled outage demand during periods of excess utility capacity;
- Removing or reducing ratchets in order to allow customers to ration themselves efficiently every month; and

[25] Pacific Power, Schedule 47: Delivery Service, Sheet No. 47-1, Effective March 22, 2011.
[26] Pacific Gas and Electric Company, Electric Schedule S: Standby Service, Sheet No. 28241-E, Effective April 15, 2009.
[27] American Electric Power Ohio, Schedule SBS: Standby Service, Sheet No. 227-2, Effective September 2012.

- Recovering costs in a manner that penalizes customers who use the grid inefficiently while allowing customer to avoid charges when not taking service.

Examples of successful standby rates that promote efficient consumption include:

- NSTAR Rate T-2 (New York), Portland General Electric Rate 75 (Oregon), and MidAmerican's Rider SPS (Iowa) have no demand ratchets.[28]
- Hawaiian Electric Company Rate SS (Hawaii) charges standby customers a fairly high ($0.156/kWh) energy charge during both scheduled and unscheduled DG outages. This provides the customer a strong and direct incentive to ensure that their generator is well maintained.[29]
- Southern California Edison rate TOU-8-RTP-S (California) delineates the price for standby energy in hourly allotments corresponding to ambient air temperature, voltage taken, and day of week. This gives standby customers a detailed knowledge of how utility costs are incurred and how and when to operate to avoid high costs.[30]

In addition to these criteria, further guidance on ratemaking can be found in Federal Regulation, specifically those created by the Public Utility Regulation Policies Act. According to U.S. Code:

> "Rates for sales shall be just and reasonable and in the public interest and shall not discriminate against any qualifying facility [standby customer] in comparison to rates for sales to other customers served by the electric utility. Rates for sales which are based on accurate data and consistent system wide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics."[31]

These three criteria along with PURPA language help structure the analysis of Minnesota standby rates. Analyzing rates using these criteria is also useful because there are multiple approaches to creating successful standby rates. Standby rates and rate structures vary widely between states and utilities based on the costs inherent to specific situations and geographies. Applying these three criteria to standby rates, as opposed to a one size fits all structure, allows for flexibility in creating rates that recognize and recover utility costs.

Standby rates in Minnesota were further analyzed using an analytic modelling approach. The three criteria help organize and classify the rate barriers uncovered in the analytic modeling of standby rates. The analytic model analyzed the economic effects both current and modified standby rates have on customers with on-site generation. Possible rate modifications were identified as those that adhere to

[28] Environmental Protection Agency, 15.
[29] Hawaiian Electric Company, Schedule SS: Standby Service, Sheet No. 69, Effective May 15, 2008.
[30] Southern California Edison, Schedule TOU-8-RTP-S:TIME-OF-USE-GENERAL SERVICE – LARGE REAL TIME PRICING – STANDBY, Sheet No. 52242-E, Effective April 1, 2013.
[31] *Public Utility Regulatory Policies* Act 18 U.S.C. § 292.305 (2012).

the above criteria while also improving the analytic modeling results. The following section explains the analytic model.

2.4 Analytic Approach to Modeling Standby Rates

In order to evaluate the economic effects of Minnesota standby rates on DG/CHP systems it was necessary to create two models that examine the economic effects of standby rates. The first model calculated the avoided rates of each utility's standby structure while the second analyzed how possible modifications to this avoided rate might affect the economic potential of CHP projects. The avoided rate is an analytic approach that quantifies the economic impacts standby rates may present to self-generating customers.

2.4.1 Avoided Rate Model

Created in Microsoft Excel, the avoided rate model analyzes the extent that standby rates allow DG customers to avoid electric charges. As a metric for evaluation, this model used the guidelines and methodology presented by the EPA CHP partnership in the paper "Standby Rates for Customer-sited Resources: Issues, Considerations, and the Elements of Model Tariffs"; specifically, the EPA's concept and application of the avoided rate.[32] This metric is useful because it simplistically reduces the economic and financial impact created by standby rates to a simple figure that can then be compared between utilities and states.

The concept of avoided rate evaluates the financial impacts of standby rates on DG systems by comparing the per kWh cost of full-requirements customers to that of standby customers. Ideally, a decrease in electricity purchased from the utility would be commensurate with a decrease in monthly electric costs. If a customer reduces their purchased electricity by 50% one would expect their bill to decrease by a similar amount. However, many standby rates are created such that they increase demand charges when a customer decreases energy consumption, thus negating many economic benefits. The avoided rate, then, is a metric that measures the amount of savings per kWh a DG customer receives when not purchasing electricity from the utility. In essence, it compares the value of a purchased kWh to the value of an avoided kWh. This rate requires the comparison between the same facility when on a full-requirements rate and when on a standby rate. After modeling each facility's usage during one year it is possible to aggregate all charges into a simple cost per kWh. This aggregate cost includes the cost of generation, transmission, distribution, demand, taxes and all applicable riders for both full-requirements and standby rates. The avoided rate is created through dividing the money not paid to the utility by the electricity not purchased from the utility. When the avoided rate closely matches the full-requirements rate, the user experiences increased savings.

For example, a hypothetical facility purchases 1,000,000 kWhs per year from the utility at an aggregate cost of 10¢ per kWh for a total cost of $100,000. Say this same facility installs a CHP system that reduces

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[32] Environmental Protection Agency. Office of Atmospheric Programs. Climate Protection Partnerships Division. *Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs*, by the Regulatory Assistance Project and ICF International, (Washington, D.C., 2009).

their need for purchased electricity to 500,000 kWhs per year. In an ideal economic situation, the annual bill would be half the normal bill, or $50,000. Under this ideally constructed scenario the avoided rate from the 500,000 kWhs *not* purchased would be 10¢ ($50,000/500,000 kWh). Thus, this situation would have an avoided rate of 100% the full-requirements rate.

There are limitations in using the avoided rate metric, however. Though simple to calculate and communicate, the avoided rate metric is a blunt tool that can over simplify situations. The economic effect of standby rates is largely related to the specific attributes and operating schedules of a customer's generator. While the avoided rate can give a general overview of economic barriers, the actual effects on standby customers may vary greatly depending on actual circumstances. Because of the limitations in the avoided rate analysis, we also included the three criteria of transparency, flexibility and economic efficiency in the analysis of standby rates.

2.4.2 Economic Potential Analysis

The Energy Resources Center worked in conjunction with ICF International in order to develop the economic potential analysis for CHP projects in Minnesota. This model analyzed how changes in the avoided rate from modifications to standby rates might affect the overall project paybacks of CHP projects in the state.

The process for examining how changes to standby rates might affect future installed CHP capacity begins with identifying sites that are technically conducive for CHP applications in terms of their coincidental electric and thermal loads. The technical potential for additional CHP applications in Minnesota is greater than 1,975 MW; 1,226 MW in the industrial sector and 748 in the commercial sector. 1,798 resides within the four major IOUs (See Appendix A for technical potential methodology and Appendix B for a breakout of technical potential by utility, economic sector and SIC code). The CHP technical potential is an estimation of market size constrained only by technological limits – the ability of CHP technologies to fit customer needs – and represents the upper most bound for CHP capacity as technical potential does not consider capital costs, regulatory barriers, energy costs, avoided electric costs, or other factors impacting the economic feasibility of CHP systems. In comparison, Minnesota has 918 MW of already installed CHP capacity and 11,547 MW of a combined utility generating capacity.[33]

The technical potential was then further classified using five different CHP system size ranges (50 to 500 kW, 500 to 1,000 kW, 1 to 5 MW, 5 to 20 MW, and greater than 20 MW) and four different market scenarios: [34]

- CHP with heating only – High load factor applications
- CHP with heating only – Low load factor applications
- CHP with heating and cooling – High load factor applications

[33] U.S. Energy Information Administration, Office of Electricity, Renewables and Uranium Statistics, "State Electric Profiles 2012," 2012.
[34] The model analyzed CHP performance using load factors and not according to on-peak and off-peak rate structures when energy prices may dictate more of the CHP operation than load factors.

- CHP with heating and cooling – Low load factor applications

An economic analysis was developed using assumptions specific to each size and market category such as utility specific electricity rates (including the avoided rates), state average natural gas prices, and average CHP equipment cost and performance characteristics. Because of the changing nature of natural gas prices the model included low and high gas price estimates using EIA data spanning the past five years; $4.50/MMBtu to $6.00/MMBtu for industrial customers and $5.00/MMBtu to $6.50 for commercial customers. Both the technical potential and energy price data was subjected to yearly growth rates using economic growth predictions and forecasted electric rate increases.[35] This analysis resulted in payback windows for each site residing in the technical potential analysis. The Energy Resources Center considered all technical potential with a payback less than 10 years to be economic potential. See Appendix D for greater detail on the assumptions used in the economic analysis.[36]

Economic potential was modeled with current avoided rates and with avoided rates of 100% representing the range that potential standby and net metering modifications could have on CHP potential. It is assumed that the recommendations presented in this paper will increase a customer's avoided rate to at least 100%; however, the actual impact of these recommendations largely depends on the specific operational attributes of each customer generator.

The policy recommendations within this paper focus on a more variable costs recovery for standby service. A customer generator that is often offline during coincident peak periods might see their avoided rate decrease as a result of these policy recommendations; however, a generator operating efficiently is expected to experience increased avoided costs as a result of these recommendations. This analytic approach illuminates how standby rates affect the economic potential of CHP in Minnesota. See Appendix D for a more detailed account of the economic analysis model inputs.

It should be noted that the payback ranges in the economic analysis do not factor in the effects of future grid constraint, coal plant retirements, energy resiliency, increased shale gas production, proposed carbon limits on electric generation, or other possible events affecting the price of electricity or natural gas. Depending on how future events transpire the economic potential of CHP could significantly increase from these modeled figures.

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[35] The rate at which electric rates were modeled to increase came from normalizing US DOE EIA data over the past 23 years. Appendix D-4 lays out growth assumptions.

[36] The concept of economic potential is difficult to quantify since each business and economic sector have individualized acceptable payback windows. The ERC choose a ten year range because it encapsulates the widest range of acceptable payback windows.

2.4.3 Identifying Potential Tariff Modifications

The Energy Resources Center developed potential rate recommendations for each IOU in three steps:

1. The ERC reviewed the actual standby tariffs using the three criteria presented in section 2.5 and fashioned possible modifications that would put each rate more in line with other successful standby approaches.

2. The ERC then modeled the avoided rates of both the original and modified standby rates in order to understand the economic and financial impacts on self-generating customers.

3. Possible recommendations were identified as those that allowed standby customers to avoid 100% of their full-requirements bill.

A more detailed discussion follows for each of the four investor owned utilities.

3. XCEL ENERGY – Northern States Power Company

3.1 Description of Standby Tariff – Standby Service Rider

Excel Energy offers a standby service rider (SSR) under revised sheet 101. The SSR is available to any non-residential customer who has their own generating equipment that requires 40kW or more of standby capacity. The SSR is divided into three service offerings:

1. *Unscheduled Maintenance Service*
2. *Scheduled Maintenance Service*
3. *Non-Firm Standby Service*

3.2 Description of Standby Charges

The SSR Includes three charges:

1. Distribution Standby Capacity Fee
2. Demand Charges issued when standby is taken
3. Energy charges issued when standby is taken.

In September 2012 Xcel Energy revised their previous standby rates. Xcel's current standby tariff includes separate monthly reservation fees for firm unscheduled and firm scheduled maintenance service and for non-firm standby service. If a customer wishes to procure standby for both scheduled and unscheduled outages they must pay both reservation charges. The reservation charge includes a monthly customer charge and a distribution capacity fee delineated by voltage class. There is a small price difference ($0.10 per kW) between the unscheduled and scheduled reservation fee. Firm customers are allotted 964 hours of unscheduled use exempt from demand usage rates. Use of this grace period will be measured in terms of kWhs used by a customer. The maximum amount of standby energy available to the customer is 964 hours multiplied by the contracted Standby capacity. Non-firm customers only pay a reservation fee for distribution and transmission standby capacity and are allotted no grace period from demand usage charges. All usage demand and energy charges are billed per the full-requirements rate to which this rider is attached.

Notwithstanding the demand usage grace period, in the event a customer requires backup service at times in which the company would have insufficient accredited capacity thereby requiring additional capacity purchases as a result of such backup service, the standby customer shall pay peak demand charges for that month and the five subsequent months thereafter. If the customer gives a three hour notification the customer will only be changed one-sixth of any additional capacity costs but shall not be charged any after-the-fact capacity purchases. If notification is less than three hours the customer will be charged one-sixth of any additional capacity purchases. Additionally, the billing demand for the next five months shall be set as the maximum demand placed on the grid during the time of system peak.

This peak capacity provision is waived if the company has obtained appropriate accreditation from MISO for the customer's generation.

The customer's standby contract capacity is set forth in an electric service agreement. The quantity of standby capacity can be set at different levels for the summer and winter seasons. A customer seems able to set their contract capacity below the nameplate generation rating of their generator.

For customers with a contract capacity ranging from 40 kW to 10,000 kW scheduled maintenance on the generating unit must occur during the months of April, May, October or November. Customers with a contract capacity greater than 10,000 kW must provide an annual projection of scheduled maintenance to the company. The amount of advanced notice that the customer must provide is a function of the expected duration of the maintenance outage.

General Service or General Time of Day Service demand charges shall not apply to use during qualifying scheduled maintenance periods. Further, qualifying scheduled maintenance period time and energy will not count against the grace period.

3.3 Assessment of Xcel's Standby Rates

Xcel's current standby rates were recently revised; however, there still remain structural issues which if addressed would improve the economic climate for CHP in Minnesota. First, Xcel's standby tariff does not transparently display the cost components in the reservation rate. The reservation rate does not include any seasonal or on/off-peak differentiated pricing nor does it unbundle and separately price the components (generation, distribution and transmission) that comprise the standby service. The costs to provide capacity to full-requirements customers differs greatly between seasons and peak periods ($12.14 per kW in summer peak compared to $2.10 per kW during winter off-peak)[37]; however, this transparent cost differential is not present in the standby rate. Introducing seasonality and time-of-use distinctions in the reservation rate would ensure consistency with the design of other rate components in Xcel Energy's electric tariff book. Additionally, bundling of standby components masks the drivers of each cost component; transparency entails the unbundling of capacity costs to reflect the drivers of cost for each component.

Xcel Energy's standby rate also fails at providing flexible options for self-generating customers to take service. By paying the reservation rate standby customers are entitled up to 964 hours of unscheduled standby service (corresponding to an 11% FOR) even if they do not need that level of service. Standby customers operating under an 11% FOR are paying for service left unused. A flexible approach would allow the standby customer to choose the level of standby support required.

[37] Xcel Energy, Rate A15: General Time of Day Service; Section 5, Sheet 29, effective January 1, 2013.

Lastly, Xcel's standby rate does not provide necessary price signals to incentivize standby customers to more efficiently operate their generating units. Firm standby customers are paying an 11% FOR which is generally greater than most reliable CHP generator units.[38] This grace period does not encourage customers to reduce the duration of forced outages but can, in fact, incentivize standby customer to go offline when they otherwise might not since they will face few additional charges. Instead of tying the reservation rate to an 11% FOR covering all standby customers no matter their needed level of service, the reservation rate should be tied to a customer's own or chosen forced outage rate. Under such a structure the grace period would be terminated in favor of an on-peak, per day kW charge to recover the costs associated with a forced outage. This should result in a lower monthly reservation charge but a higher variable usage charge. While this rate structure might increase costs for standby customers with a large FOR it will, more importantly, encourage customers to reduce their FOR which will commensurately decrease the fixed monthly reservation charges further encouraging efficient consumption. According to the Regulatory Assistance Project, the use of daily standby demand charges provides incentives to improve the performance of self-generating units.[39]

In addition, a standby customer must reserve backup service and maintenance service separately even though the standby contract capacity that covers one service ought to cover both. The capacity reserved on the distribution system for backup service often is the exact same capacity that would be used during a scheduled outage.

3.4 Potential Recommendations to Xcel Energy's Standby Rate

Following are suggested modifications to Xcel's standby tariffs for consideration to lessen the barriers to future DG and CHP projects:

Transparency

1. *Combine backup service and maintenance service under one reservation fee.* The amount of capacity reserved for both services is the same. Since these services will not be used simultaneously there is no need to price them separately.

2. *Unbundle the components within the reservation rate*. The drivers of cost for each component can change depending on the behavior of the customer-generator.

3. *Firm standby demand usage fees during times of system constraint should be designed as they would for full-requirements customers of similar size.* Rates for sales which are based on accurate data and consistent system wide costing principles shall not be considered discriminatory as long as they apply to other customers with similar load or cost-related characteristics.

[38] Oak Ridge National Laboratory, "Distributed Generation Operational Reliability and Availability Database," written by Energy and Environmental Analysis, Inc. (January 2004).
[39] Regulatory Assistance Project, *Standby Rates for Combined Heat and Power Systems: Economic analysis and Recommendations for Five States,* 30.

Flexibility

4. *Remove the grace period for firm backup power and instead tie the reservation charge to the customer's FOR.* The generation, transmission and shared distribution portions of the reservation charge should be calculated using the customer's own FOR. This would incentivize the customer to reduce the duration of outages.

5. *Create a buy-through option that allows self-generating customers to purchase all standby service from the market at market prices.* Currently, Xcel charges market prices to customers whose forced outages coincide with utility constraint but on the condition that the customer's standby demand may be ratcheted for five months. Instead, a buy through option would provide flexibility for customer's seeking a market solution to standby service. The reservation rate could be structured to only cover the dedicated distribution infrastructure. All standby capacity would be charged using the applicable real time MISO locational marginal pricing node plus an adder reflecting Xcel's administrative costs.

Efficient Consumption

6. *A daily on-peak, as-used demand charge should replace the grace period and additional demand charges found in the full-requirements tariff.* This variable pricing would be implemented in conjunction with the calculation of the reservation rate using a customer's FOR. The daily, on-peak charge would be structured such that the customer would pay the same amount as the supplemental rate if they took backup service for the entire month. The decrease in the monthly, fixed charges in combination with the addition of a variable usage charge would encourage the efficient consumption of grid resources. Since the costs of generation and shared distribution components are incurred during peak periods, standby demand charges for those services should apply only during on peak periods.[40]

3.5 Avoided Rate Analysis

Although Xcel's revised standby rate avoids a greater portion of the full-requirements rate than the previous rate, improvements to standby can still be implemented to help further reduce barriers towards the development of financially viable CHP projects. The standby rates financially burden customers with a smaller generating capacity, especially those with a low load factor, to a greater extent than they do for larger capacity customers.

Though this standby rate can be further improved, Xcel should be recognized for making significant changes to their past standby rates. By removing the transmission and generation reservation charges which unfairly charged standby customers to reserve capacity during off-peak periods, Xcel's avoided rates jumped from approximately 79% to the avoided rates ranging between 87 and 97%, presented in Table 6.

[40] RAP Standby Report, 31.

	500 kW	3000 kW	10,000 kW	10,000 kW
Voltage	Secondary	Primary	Transmission Transformed	Transmission
Rate	General Service	GS - Time of Day	GS - Time of Day	GS - Time of Day
Purchased Energy	4,380,000 kWh	26,280,000 kWh	87,600,000 kWh	87,600,000 kWh
Customer Charge	$295.32	$331.32	$331.32	$331.32
Demand Charge	$57,640.00	$345,840.00	$1,152,800.00	$1,152,800.00
Energy Charge	$123,997.80	$719,302.37	$2,397,674.57	$2,397,674.57
Fuel Clause	$122,972.11	$707,843.95	$2,359,479.83	$2,359,479.83
Transmission Recovery	$1,428.00	$8,568.00	$28,560.00	$28,560.00
Misc. Riders	$10,170.36	$61,022.16	$203,407.20	$203,407.20
Credits (Energy + Voltage)	-$21,780.00	-$184,932.00	-$843,360.00	-$923,244.00
Total	$294,723.59	$1,657,975.80	$5,298,892.92	$5,219,008.92
per kWh	$0.07	$0.06	$0.06	$0.06
		Standby Rates		
Purchased Energy	219,000 kWh	1,314,000 kWh	4,380,000 kWh	4,380,000 kWh
Availability	95%	95%	95%	95%
Customer Charge	$885.96	$921.96	$921.96	$921.96
RSVP Charge	$35,400.00	$151,200.00	$348,000.00	$204,000.00
Demand Charge	$0.00	$0.00	$0.00	$0.00
Energy Charge	$6,199.89	$35,965.12	$119,883.73	$119,883.73
Fuel Clause	$6,148.61	$35,392.20	$117,973.99	$117,973.99
Transmission Recovery	$1,428.00	$8,568.00	$28,560.00	$28,560.00
Misc. Riders	$508.52	$3,051.11	$10,170.36	$10,170.36
Credits (Energy + Voltage)	$0.00	-$1,182.60	-$11,388.00	-$11,782.20
Total	$50,570.97	$233,915.78	$614,122.04	$469,727.84
per kWh	$0.23	$0.18	$0.14	$0.11
Avoided Cost	$244,152.62	$1,424,060.02	$4,684,770.88	$4,749,281.08
Avoided kWh	4,161,000 kWh	24,966,000 kWh	83,220,000 kWh	83,220,000 kWh
Avoided Rate	$0.0587	$0.0570	$0.0563	$0.0571
% Avoided Rate of Full Requirements Rate	**87.20%**	**90.41%**	**93.06%**	**95.79%**

Table 6: Xcel Energy Avoided Rate Analysis

3.6 Economic Potential Analysis

Technical Analysis

As the largest investor owned utility in Minnesota, Xcel Energy also has the greatest amount of CHP technical potential with 1,442 MW (Table 7). The largest industrial sources for CHP potential are in the food (214.9 MW), chemical (192.7 MW), and petroleum refining (214.4 MW) sectors while the largest commercial/institutional source for CHP potential lie in the college and university sectors (154.7 MW). The majority of technical potential in these sectors is from installations with a capacity greater than 5 MW.

	Payback >10 Years	Payback <10 Years	Payback 0- 5 Years	Total Potential (kW)
Base Rate - $4.50/MMBtu	809	633	0	1,442
Base Rate - $6.00/MMBtu	1,442	0	0	1,442
100% Avoided Rate - $4.50/MMBtu	479	963	0	1,442
100% Avoided Rate - $6.00/MMBtu	809	633	0	1,442

Table 7: Xcel Energy Technical Potential Payback

Economic Analysis

Increasing Xcel's avoided rates to 100% results in an additional 331 MW of CHP potential moving from paybacks of greater than 10 years to paybacks less than 10 years when compared to the base case scenario. This is a significant amount of capacity that, when combined with the $4.50/MMBtu estimate represents 67% of Xcel's technical CHP potential. Though Xcel's standby rates already have high avoided rates, this analysis demonstrates that further improvements could significantly impact the payback period of CHP projects. This potential could increase above that which was modelled depending on the specific operational schedules of the customer generator. See Appendix B – 1 for a more detailed account of Xcel's CHP technical potential.

Alliant Energy

Note: On September 3, 2013 Alliant Energy announced that they will be selling their electric and natural gas operations and infrastructure in Minnesota. If approved by the Minnesota Public Utility Commission, Alliant will sell their natural gas business to Minnesota Energy Resources Corporation. The electric side of the business will be sold to twelve adjacent cooperative utilities, the largest being the Freeborn-Mower cooperative.

4.1 Description of Standby Tariff – Rider 1S

Alliant Energy offers a standby rider under revised sheet 30, which is applicable to any customer on the Large Power and Lighting tariff (sheet 21) that owns their own generating equipment and executes a contract with Alliant for an initial term not less than five years. Rider 1S is divided into two service offerings:

1. Firm Standby
2. Non-Firm Standby

4.2 Description of Standby Charges

Rider 1S includes six charges:

1. Daily Administrative Charge
2. Generation Service Reservation Charge
3. Transmission Service Reservation Charge
4. Distribution Service Reservation Charge
5. Demand Charges for when standby is actually used
6. Energy Charges for when standby is actually used

Alliant offers both firm and non-firm standby service. Under the firm standby rate a customer would pay the generation, transmission and distribution reservation fees while the non-firm standby customer would only pay for the distribution reservation fee. Firm customers are allotted 964 hours annually for use of backup service during which they are not assessed demand usage charges. The reservation fees are calculated against the contracted standby capacity which is the maximum amount of standby service the utility is obligated to supply. The tariff is unclear if the contracted standby capacity may be less than the nameplate capacity rating. According to the tariff a standby customer must state both the total capacity requirements which Alliant shall be required to supply in the event of an outage and the capacity of the power source for which Alliant will be providing standby power and to which the standby service charge applies. The tariff does state that the contracted standby capacity may be different between the summer and winter seasons.

Both demand and energy charges are priced using the rate to which this standby rider is attached, in all cases this will be the Large Power and Light tariff. Firm standby customers only pay for standby energy during the first 964 hours of backup service while non-firm customers must pay for both demand and energy during outages. The standby usage demand shall be calculated as the lesser of (i) the amount of contracted standby capacity minus the actual demand supplied by the customer's generator, or (ii) the amount of actual capacity supplied by the company.

Rider 1S states that maintenance service must be scheduled to avoid both summer and winter peak periods and be scheduled at least 30 days in advance. The rider makes no mention of how maintenance service is to be billed and if it is included under the 964 hour grace period or separate altogether.

4.3 Assessment of Alliant Energy's Standby Rates

Alliant Energy's standby rate does not include transparent price signals that encourage DG customers to use standby service efficiently or with regards to the cost of maintaining grid reliability. Similar to Xcel Energy, Alliant Energy also employs a 964 hour grace period of backup service exempt from demand charges no matter if customers need that level of service. This represents an 11% FOR which is generally greater than most reliable CHP generators. Not only does this grace period not encourage customers to reduce the duration of forced outages it in fact incentivizes standby customer to go offline when they otherwise might not. Instead of a grace period rate structure, Alliant should employ an on-peak, per day kW charge in order to efficiently recover costs associated with backup service. Similarly to Xcel Energy, this should be combined with a lower reservation rate that is calculated using a customer-generator's FOR.

Distribution cost recovery should be more transparent for non-firm standby customers. The use of the large power and light tariff to assess demand and energy charges during outages seems to enable the double billing of distribution services for non-firm customers. These customers must pay a monthly distribution reservation charge but also pay the full demand charge found in the Large Power and Light tariff when taking standby service. Rider 1S contains no stipulation by which the demand charge in the otherwise applicable tariff is pro-rated based on the already paid distribution reservation charge.

Rider 1S does not include any specification for how maintenance service should be billed or whether or not a non-firm customer may take maintenance service. The standby rate should provide clear and concise mechanisms for how maintenance service is billed and scheduled. Since maintenance service is scheduled ahead of time during off-peak periods it should largely be exempt from demand and reservation charges.

Alliant Energy requires a minimum standby contract not less than five years with potential penalties issued if a customer ends standby service within ten years. The cancellation fee is to cover the cost of installation and removal of facilities; however, this could be more properly addressed under an interconnection agreement. The standby rate should transparently explain how costs within exit fees incurred.

The rider lacks clarity as to how the standby reservation capacity is calculated. While it seems that a standby customer is able to choose a contract capacity less than the nameplate capacity of their generator the language remains vague.

4.4 Potential Recommendations to Alliant Energy's Standby Rate

Following are suggested modifications to Alliant Energy's standby tariffs for consideration:

Transparency

1. *The method in which scheduled maintenance service is billed should be specified.* Since customers have flexibility with when they schedule maintenance service (typically falls on off-peak periods during off-peak months) a customer should not have to pay either the generation, transmission or shared distribution portion of the reservation fee or the backup demand rates for such service. If needed, a demand charge reflecting the off-peak nature of the service would be more appropriate.

2. *Alliant should remove exits fees from its standby rate.* These fees, if necessary, belong in a customer's interconnection agreement. Furthermore, the components to which the utility is assessing fees should be clearly stated.

3. *Remove the distribution reservation charge from demand purchases for non-firm standby customers.* Standby usage charges for non-firm customers are taken directly from the full-requirements tariff even though non-firm customers are already paying to reserve distribution service. Alliant energy should remove the distribution cost component from the full-requirements tariff when non-firm standby customers use standby service.

Flexibility

4. *Remove the grace period for firm backup power and instead tie the reservation charge to the customer's FOR.* The generation, transmission and shared distribution portions of the reservation charge should be calculated using the customer's own FOR. This would incentivize the customer to reduce the duration of outages and would further allow standby customers to minimize monthly charges.

Efficient Consumption

5. *A daily on-peak, as-used demand charge should replace the grace period and additional demand charges found in the full-requirements tariff.* This variable pricing would be implemented in conjunction with the calculation of the reservation rate using a customer's FOR. The daily, on-peak charge would be structured such that the customer would pay the

same amount as the supplemental rate if they took backup service for the entire month. The decrease in the monthly, fixed charges in combination with the addition of a variable usage charge would encourage the efficient consumption of grid resources. Since the costs of generation and shared distribution components are incurred during peak periods, standby demand charges for those services should apply only during on peak periods.

4.5 Avoided Rate Modeling of Standby Tariffs

Out of the four IOUs in Minnesota, Alliant Energy has the most burdensome standby rates. The analytic model found Alliant to have the lowest avoided rates in the state (Table 8). Since Alliant will shortly be leaving the state it is unclear how standby mitigation might affect potential CHP sites. Needless to say, the market uncertainty for CHP in Alliant's territory will likely hinder development until customers are familiar with their new electric utility.

	500 kW	1000 kW	3000 kW	10000 kW
Voltage	Secondary	Primary	Primary	Transmission
Rate	Large Power and Light	Large Power and Light	Large Power and Light	Large Power and Light
Purchased Energy	4,380,000 kWh	8,760,000 kWh	26,280,000 kWh	87,600,000 kWh
Customer Charge	$3,000.00	$3,000.00	$3,000.00	$3,000.00
Demand Charge	$66,880.00	$131,486.08	$394,458.24	$1,337,600.00
Energy Charge	$205,334.40	$403,687.43	$1,211,062.29	$4,106,688.00
Misc. Riders	$9,723.60	$19,447.20	$58,341.60	$194,472.00
Credits (Energy + Voltage)	-$18,133.20	-$41,186.40	-$123,559.20	-$515,064.00
Total	$266,804.80	$516,434.31	$1,543,302.93	$5,126,696.00
per kWh	$0.06	$0.06	$0.06	$0.06
		Standby Rates		
Purchased Energy	219,000 kWh	438,000 kWh	1,314,000 kWh	4,380,000 kWh
Availability	95%	95%	95%	95%
Additional Customer Charge	$780.00	$780.00	$780.00	$780.00
RSVP Charge	$56,700.00	$113,400.00	$340,200.00	$1,134,000.00
Demand Charge	$0.00	$0.00	$0.00	$0.00
Energy Charge	$10,266.72	$20,184.37	$60,553.11	$205,334.40
Misc. Riders	$486.18	$972.36	$2,917.08	$9,723.60
Credits (Energy + Voltage)	($906.66)	($3,043.32)	($9,129.96)	($56,233.20)
Total	70,326.23	135,293.41	398,320.23	1,296,604.79
per kWh	0.32	0.31	0.30	0.30
Avoided Cost	196,478.56	381,140.90	1,144,982.70	3,830,091.20
Avoided kWh	4,161,000 kWh	8,322,000 kWh	24,966,000 kWh	83,220,000 kWh
Avoided Rate	$0.047	$0.046	$0.046	$0.046
% Avoided Rate of Full Requirements Rate	77.52%	77.69%	78.10%	78.64%

Table 8: Alliant Energy Avoided Rate Analysis

4.6 Economic potential Analysis

Technical Analysis

The entire CHP technical potential within Alliant's electric territory is found in high load factor heating only applications. The only marginally significant source of CHP technical potential is found in the chemical sector (35 MW). The majority of capacity in this sector is found in systems ranging from 1 – 5 MW in capacity.

	Payback >10 Years	Payback <10 Years	Payback 0-5 Years	Total Potential, MW
Base Rate - $4.50/MMBtu	52	5	0	57
Base Rate - $6.00/MMBtu	57	0	0	57
100% Avoided Rate - $4.50/MMBtu	52	5	0	57
100% Avoided Rate - $6.00/MMBtu	52	5	0	57

Table 9: Alliant Energy Technical Potential Payback

Economic Analysis

As can be seen from Table 9 above, low natural gas prices have the same impact as modified standby rates on lowering the payback window for potential CHP projects. Though Alliant Energy is not a significant source of CHP economic potential in Minnesota with projects resulting in paybacks less than 10 years, this could change depending on the rate policies and structures of the future utilities serving this territory.

5. Minnesota Power

5.1 Description of Standby Tariff – Rider for Standby Service (RSS)

Minnesota Power (MN Power) offers a standby rider under page 61, 4th revision which is applicable to any customer on the residential, general, large light and power, municipal pumping or large power service rates who has entered into a parallel interconnection agreement with the utility and who executes a contract of not less than one year. Rider for Standby Service is divided into two service offerings:

1. Firm Standby
2. Non-Firm Standby

5.2 Description of Standby Charges

RSS is includes five charges:

1. Standby Reservation Fee
2. Standby Usage Fee – Summer Peak
3. Standby Usage Fee – Winter Peak
4. Standby Usage Fee – Off-Peak
5. Standby Energy

The standby reservation fee only applies to firm standby customers and is calculated using the contracted standby demand. The contracted standby demand shall be specified by the customer as the maximum amount of standby service MN Power is obligated to serve.

If a customer opts for firm standby service and pays the monthly standby reservation fee, they are exempt from any standby usage demand fees if (i) the contracted standby demand equals the nameplate capacity rating or (ii) the actual demand supplied by the generator is greater than the difference between the nameplate capacity rating of the generator and the contracted standby demand. This means that if a customer intends to use load shedding to address a portion of their standby needs, they must generate more than the difference between the nameplate capacity and the amount of capacity available to shed during an outage. If a customer's generation unit goes offline completely and their contracted standby demand is less than the nameplate capacity, they must pay a standby demand usage fee no matter the amount of capacity they are able to shed.

The standby usage fees are calculated as a $/kW per month charge during months in which a generator is offline for both backup or maintenance service. The Standby usage demand fees are divided between summer-peak, winter-peak and off-peak periods, though these names are misleading since they only refer to months and not time periods during those months. The Standby demand used to calculate the usage fee shall be determined as the smaller of the following two amounts: (i) nameplate capacity minus the actual demand supplied by the generator minus the contracted standby demand, or (ii) the amount of actual capacity supplied by MN Power minus the contracted standby demand, but in neither case less than zero. The standby usage demand fees are separated by rate class and then divided into voltages categories.

The per kWh rate for standby usage energy charges are provided in the standby rider and are determined as the summation of the smaller of the following two amounts for each 15 minute period in the outage: (i) the nameplate capacity rating of the generator minus the actual demand supplied by the generator, or (ii) the actual capacity supplied by MN Power.

The standby rider contains no provisions for scheduled maintenance service nor does the rider state how many hours a standby customer is entitled to be offline. The rider only states that the customer should operate their generator in a manner agreed to by the company.

5.3 Assessment of Minnesota Power's Standby Rate

A general concern with Minnesota Power's rider for standby service is that it lacks sufficient detail as to the proper function of many of its rate components. The standby rider is opaque with regards to rate functions such as the calculation of the usage fee, maintenance demand specifications, allowed backup hours, and the charges that inhabit the reservation and demand fees. This rate is structured in such a way that implies that a firm standby customer reserving their entire nameplate capacity could go offline indefinitely without any additional monthly charges. The rate should be more transparent to allow customers to understand how their standby rate assesses charges.

Though the modelling suggests that Minnesota Power's standby rate allows customers to avoid a large percentage of their full-requirements charges, the results are uncertain because of opaque rate functions. Regardless, the modelling results of Minnesota Power's standby rates are structured without adequate price signals that would incentivize more efficient consumption. The standby rate fails to account for load diversity and time-of-use cost components, resulting in unclear signals to standby customers regarding the cost drivers behind utility investments. Furthermore, the tariff does not incorporate daily as-used demand charges that would give standby customers an incentive to reduce the duration of their generation unit outages.

Finally, Minnesota Power's standby tariff does not provide the standby customer with adequate flexibility to meets its standby requirements though alternative means such as load shedding.

5.4 Potential Recommendations to Minnesota Power's Standby Rate

Following are suggested modifications to Minnesota Power's standby tariffs for consideration:

Transparency

1. *The reservation and usage rates should be unbundled into corresponding generation, transmission and distribution cost components while the overarching mechanics should be made more transparent.* Under Minnesota Power's standby tariff, it is difficult to see the level of transmission and generation charges being included in the reservation fee. Unbundling the rates would make them more transparent. Additionally, the mechanics stipulating the use, duration and pricing of standby service should be made clear.

2. *Minnesota Power should specify how maintenance is treated and billed.* Since customers have flexibility with when they schedule maintenance service (typically falling on off-peak periods during off-peak months) a customer should not have to pay either the reservation fee or the forced outage usage demand rates for such service. By sending clear and specific price signals, Minnesota Power can help shift maintenance service towards those times when their marginal costs are low and thus minimizing the cost of providing standby service.

3. *Standby reservation charges and demand usage charges should reflect load diversity.* The standby reservation charges and the standby demand usage rates are greater than the demand charges in the full-requirements rates even though the coincident factor of standby customer is far less than that of full-requirements customers. Under this structure a standby customer pays more to reserve capacity than a full-requirements customer pays to use that same capacity even though the standby customer is using shared infrastructure far less. Charges for shared infrastructure should reflect load diversity and load diversity can be recognized by designing shared infrastructure demand charges on a coincident peak basis.

Flexibility

4. *The standby reservation charge should incorporate a customer's FOR to allow self-generating customers to avoid a greater amount of the fixed monthly charges.* Currently the standby reservation fee allows the customer to use an undefined amount of standby service. A better approach would be to tie the reservation rate to a customer's FOR to allow well operating customers to decrease their monthly fixed charges.

Efficient Consumption

5. *The standby demand usage fees should only apply during on-peak hours and be charged on a daily basis.* This rate design would encourage DG customers to shift their use of standby service to off-peak periods when the marginal cost to provide service is generally much lower. Additionally, the inclusion of a daily standby demand rate would encourage standby customer to limit their use of backup service.

6. *Standby energy usage fee should reflect time-of-use cost drivers.* Time-of-use energy rates send clear price signals as to the cost for the utility to generate needed energy. This would further incentivize the use of off-peak standby services.

5.5 Avoided Rate Analysis

Minnesota Power's standby rates allow customers to avoid a significant portion of the full-requirements rate with avoided rates ranging between 90 and 97% (Table 10).

	500 kW	3000 kW	10,000 kW	10,000 kW
Voltage	Secondary	Primary	Primary	Transmission
Rate	General Service	General Service	Large Light and Power	Large Light and Power
Purchased Energy	4,380,000 kWh	26,280,000 kWh	87,600,000 kWh	87,600,000 kWh
Customer Charge	$126.00	$126.00	$0.00	$0.00
Demand Charge	$35,160.00	$210,960.00	$2,424,840.00	$2,424,840.00
Energy Charge	$232,402.80	$1,394,416.80	$3,276,240.00	$3,276,240.00
Fuel Clause	$51,128.34	$306,770.04	$899,067.95	$899,067.95
Transmission Recovery	$1,445.40	$8,672.40	$26,988.00	$26,988.00
Misc. Riders	$22,854.84	$137,129.04	$482,272.80	$482,272.80
Credits (Energy + Voltage)	$0.00	-$63,000.00	-$210,000.00	-$458,784.00
Total	$343,117.38	$1,995,074.28	$6,899,408.75	$6,650,624.75
per kWh	$0.08	$0.08	$0.08	$0.08
		Standby Rates		
Purchased Energy	219,000 kWh	1,314,000 kWh	4,380,000 kWh	4,380,000 kWh
Availability	95%	95%	95%	95%
Additional Customer Charge	$0.00	$0.00	$0.00	$0.00
RSVP Charge	$41,580.00	$169,200.00	$736,800.00	$369,600.00
Demand Charge	$0.00	$0.00		
Energy Charge	$3,416.40	$3,416.40	$68,766.00	$68,766.00
Fuel Clause	$2,556.42	$2,556.42	$44,953.40	$44,953.40
Transmission Recovery	$72.27	$72.27	$569.40	$569.40
Misc. Riders	$1,142.74	$1,142.74	$19,613.64	$19,613.64
Credits (Energy + Voltage)	$0.00	$0.00	($12,439.20)	($12,439.20)
Total	$48,893.83	$176,513.83	$858,263.24	$491,063.24
per kWh	$0.22	$0.13	$0.20	$0.11
Avoided Cost	$294,223.55	$1,818,560.45	$6,041,145.52	$6,159,561.52
Avoided kWh	4,161,000 kWh	24,966,000 kWh	83,220,000 kWh	83,220,000 kWh
Avoided Rate	$0.071	$0.073	$0.073	$0.074
% Avoided Rate of Full Requirements Rate	90.26%	95.95%	92.17%	97.49%

Table 10: Minnesota Power Avoided Rate Analysis

5.6 Economic potential Analysis

Technical Analysis

Minnesota Power has the second largest technical potential of CHP capacity of investor owned utilities in Minnesota with 236 MW (Table 11). Of this technical potential 201 MW is found in high load factor heating only applications. By far the largest source of this potential exists in the paper sector (120 MW) and within that from sites with a CHP capacity greater than 20 MW (81.2 MW). Though the largest customers by capacity already experience high avoided rates, even marginal improvements may have a noticeable impact on decreasing system payback.

	Payback >10 Years	Payback <10 Years	Payback 0- 5 Years	Total Potential, MW
Base Rate - $4.50/MMBtu	95	141	0	236
Base Rate - $6.00/MMBtu	236	0	0	236
100% Avoided Rate - $4.50/MMBtu	95	141	0	236
100% Avoided Rate - $6.00/MMBtu	95	141	0	236

Table 11: Minnesota Power Technical Potential Payback

Economic Analysis

Because of uncertainties within Minnesota Power's standby rate, the avoided rates as presented in Table 10 reflect the uppermost estimation of avoided rate percentages. As a result the economic potential by payback category presented in Table 11 reflects the lower end of potential CHP capacity. As currently modelled, reduced natural gas prices have a similar effect on payback potential as do modified standby rates. In fact, the base case scenario with gas at $4.50/MMBtu lowers the payback windows for the same amount of capacity as does the scenario with 100% avoided rates; though one can assume that modified standby rates further reduce CHP payback within the less than 10 year payback category. However, capturing 141 MW of economic potential through standby mitigation represents a significant portion of Minnesota Power's technical potential. While the model estimates Minnesota Power to have high avoided rates, it demonstrates that even marginal improvements to standby can have a significant effect on CHP's economic potential. The effect on economic potential would be even more pronounced if the avoided rates were lower than currently modelled.

6. Otter Tail Power Company

6.1 Description of Standby Tariff –Standby Service (SS)

Otter Tail Power offers standby service under section 11.01 of the sixth revised tariff sheet which is applicable to any customer that request to become a firm standby customer that uses an extended parallel generation system and who has entered into a contract for standby service. Rate SS is divided into two service offerings:

1. Firm Standby
2. Non-Firm Standby

6.2 Description of Standby Charges

Rate SS has five charges:

1. Firm Standby Fixed Charges
2. Firm Standby On-Peak Demand Charges – Summer expressed on a daily basis
3. Firm Standby Off-Peak Demand Charges – Winter expressed on a daily basis
4. Firm Standby Energy Charges – Summer
5. Firm Standby Energy Charges – Winter

The five charges listed above are applied to both the firm and non-firm standby options and are further divided into a transmission, primary and secondary service voltage categories.

The firm standby fixed charge is broken out into a customer charge of $199/month for all voltages, a summer reservation charge per month per kW, a winter reservation charge per month per kW and a standby facilities charge per month per kW. Non-firm customers avoid all of these charges except for the customer charge.

All three reservation charges are calculated using the contracted backup demand figure which is the amount of capacity selected to back up the customer's generation, not to exceed the capability of the customer's generator. This figure may be less than the nameplate capacity if the customer opts to use load shed to self-supply a portion of standby service. Firm standby service allows the customer to use back-up service no more than 120 on-peak hours in the summer and 240 on-peak hours in the winter. If the customer exceeds those limits they may be required to take service under a standard, non-standby rate schedule.

Non-firm standby customers are not allowed to use backup service during any on-peak period. The service is only available in the summer and winter shoulder and off-peak periods.

When firm back-up service is taken the customer is charged for the metered demand and energy used during an outage. Though Backup Demand is charged on a per day on-peak basis the Backup Demand Charge, as further defined in attachment number one, is the sum of the ten highest daily Backup Demands multiplied by the applicable Backup Demand Charge. There is no demand charge when using standby service in the shoulder or off-peak periods.

The Standby Energy Charges are divided between summer and winter seasons and between on-peak, off-peak and should periods. Non-firm standby customers are not allowed to use standby energy during the on-peak periods.

Scheduled Maintenance Service does not require a reservation charge (“Firm Standby Fixed Charge”). The daily on-peak backup demand charge will be waived for a maximum continuous period of 30 days per calendar year to allow for the maintenance of a customer’s generator. This waiver shall only be granted in the months of April, May, October and November. All other standby energy charges apply.

If supplemental service is needed it shall be supplied under standard rate schedule 10.06.

6.3 Assessment of Otter Tail’s Standby Rate

Otter Tail‘s standby rate has the greatest avoided rates of all Minnesota electric utilities included in this report. This is largely due to the use of daily on-peak demand charges associated with backup service. The use of daily demand charges incentivizes DG customers to reduce the duration of their generating unit outages in order to save more money. Furthermore, the time-of-use price signals encourage customers to shift their use of utility resources to off-peak or shoulder periods.

Though the hourly limit for on-peak backup service may at first seem limiting, this figure only captures the number of hours a generator is offline during on-peak periods and not cumulatively. The summer on-peak period spans only 6 hours a day Monday to Friday while the Winter Peak spans only 9 hours a day. Therefore, the maximum allowed backup time during the summer and winter are, respectively, 20 and 26 week days.

Otter Tail incentivizes customer’s to self-supply standby reserves though multiple methods including the negation of reservations fees for customers with a physical assurance load limiting device, allowing customers to contract for backup capacity less than their nameplate capacity and by offering non-firm standby service. Customers who are able to self-supply standby reserves during on-peak periods whether through load shedding, physical assurance or other generation options will experience increased savings through Rate SS.

There are a few drawbacks in Rate SS, one of which is that it does not use a customer’s FOR when calculating the reservation charges. Customers with widely differing FORs will all pay the same reservation charge for firm standby service. This remains a minor point due to the miniscule price of the reservation charges (all <$1.00 / kW) and the use of a daily on-peak demand charge to recover costs incurred during forced outages.

The rate is slightly complicated with regards to scheduled maintenance service and the backup demand charge. Though the rate never precludes the use of maintenance service for non-firm standby customers it doesn't affirm it either. The rate is unclear if a customer must pay a reservation charge to access the 30 day on-peak demand waiver. The method in which backup demand is charged is less transparent than it ought it be. A potential standby rate customer must read the details of attachment one in order to understand how specifically the backup demand is charged.

6.4 Potential Recommendations to Otter Tail's Standby Rate

The following are suggested modifications to Otter Tail's Standby Rate for consideration:

Transparency

1. *The reservation charges should be unbundled into generation, distribution and transmission cost components.* With the current standby rate structure it is difficult to assess the level of generation and transmission charges that a standby customer is paying in the reservation fee. While the reservation charges are small this in no way prevents them from being unbundled. Unbundling the reservation charge would make the rate design of Rate SS more transparent.

2. *Clearly state whether non-firm standby customers may take scheduled maintenance service.* This will add transparency and remove misunderstandings from the rate.

Flexibility

3. *The FOR should be used in the calculation of a customer's reservation charge.* The inclusion of a customer's FOR further incentivizes the customer to limit their use of backup service. The FOR would be applied to the unbundled generation and transmission components and any shared distribution infrastructure.

6.5 Avoided Rate Analysis

Otter Tail Power has the greatest avoided rates currently in place of all IOUs in Minnesota with rates in the 96-96% range (Table 12).

	500 kW	**1,000 kW**	**3,000 kW**	**10,000 kW**
Voltage	Secondary	Primary	Primary	Transmission
Rate	General Service	Large General	Large General TOU	Large General TOU
Purchased Energy	4,380,000 kWh	8,760,000 kWh	26,280,000 kWh	87,600,000 kWh
Customer Charge	$228.00	$480.00	$720.00	$720.00
Facilities Charge	$3,600.00	$1,440.00	$4,320.00	$0.00
Demand Charge	$6,520.00	$73,800.00	$221,400.00	$612,400.00
Energy Charge	$313,856.20	$412,274.80	$1,198,136.49	$3,719,934.00
Misc. Riders	$5,518.80	$4,692.00	$14,076.00	$46,920.00
Total	$329,723.00	$492,686.80	$1,438,652.49	$4,379,974.00
per kWh	$0.08	$0.06	$0.05	$0.05
		Standby Rates		
Purchased Energy	219,000 kWh	438,000 kWh	1,314,000 kWh	4,380,000 kWh
Availability	95%	95%	95%	95%
Customer Charge	$2,388.00	$2,388.00	$2,388.00	$2,388.00
Facilities Charge	$4,335.60	$6,339.60	$19,018.80	$0.00
RSVP Charge	$550.20	$1,049.60	$3,148.80	$9,704.00
Demand Charge	$6,656.38	$12,680.10	$38,040.30	$117,000.75
Energy Charge	$10,216.86	$19,733.13	$59,199.38	$185,996.70
Misc. Riders	$275.94	$551.88	$1,655.64	$5,518.80
Total	$24,422.99	$42,742.31	$123,450.92	$320,608.25
per kWh	$0.11	$0.10	$0.09	$0.07
Avoided Cost	$305,300.01	$449,944.49	$1,315,201.57	$4,059,365.75
Avoided kWh	4,161,000 kWh	8,322,000 kWh	24,966,000 kWh	83,220,000 kWh
Avoided Rate	$0.073	$0.054	$0.053	$0.049
% Avoided Rate of Full Requirements Rate	97.47%	96.13%	96.23%	97.56%

Table 12: Otter Tail Electric Avoided Rate Analysis

6.6 Economic Potential Analysis

Technical Analysis

Otter Tail Power has 63 MW of CHP technical potential within its territory (Table 13), 27 MW of which is found in the industrial sector and 36 MW in the commercial sector. Of the CHP technical potential within Otter Tail Power's electric territory 55 MW is found in high load factor heating and cooling only applications. Additionally, 45% (28 MW) of total technical potential is found in institutional and governmental sectors. The majority of all technical potential is in systems with a capacity less than 5 MW. There are no individual market sectors that have any significant technical potential.

	Payback >10 Years	Payback <10 Years	Payback 0- 5 Years	Total Potential, MW
Base Rate - $4.50/MMBtu	63	0	0	63
Base Rate - $6.00/MMBtu	63	0	0	63
100% Avoided Rate - $4.50/MMBtu	57	6	0	63
100% Avoided Rate - $6.00/MMBtu	57	6	0	63

Table 13: Otter Tail Power Technical Potential Payback

Economic Analysis

Unlike the previous three utilities, modifications to Otter Tail Power's standby rates affect CHP payback windows to a greater extent than natural gas prices with 9.5% of the CHP projects moving from paybacks of greater than 10 years to paybacks less than 10 years (Table 13). This corresponds to the fact that most of the technical potential is found in the size categories that have the lowest avoided rates. Though the amount of CHP potential is low for projects with paybacks less than 10 years, it would be misleading to assume that there would be no market penetration since Otter Tail Power has a high percentage of technical potential within sectors that have a tolerance for increased payback (e.g. institutional facilities).

7. Net Metering Rates

7.1 Definition of Key Concepts

Though net metering was originally implemented in order to encourage private investment in renewable energy resources such as solar and wind, it can provide a needed incentive for smaller CHP projects to become financially feasible.[41]

Net metering allows for the flow of electricity both to and from the customer – typically through a single, bi-directional meter – allowing qualified DG customers to export electricity to the grid during times when their generation exceeds their on-site consumption. In the instances during a billing cycle when a customer's generation exceeds their electric purchases the net excess generation (NEG) in the form of a kilo-watt hours (kWh) is stored in a bank to be credited against future kWh purchases. In effect, the customer uses excess generation to offset electricity that the customer otherwise would have to purchase at the utility's full retail rate. Some states require utilities to monetarily credit all NEG that's been stored for a specific period of time, other states expire NEG credits after a set amount of time while some allow for indefinite rollover. The monetary rate at which NEG is credited can vary depending on state regulations and utility policy from the average retail rate to the much lower PURPA avoided rate.

While net metering rates allow customers to reduce the energy potion of their bill, there is no mechanism by which billing demand is similarly reduced.[42] A net metered customer must still pay for their maximum level of demand imposed on the grid through the demand charge in their full-requirements rate. Because net metering eligible technologies have historically been either quite small or limited to low load factor (renewable) applications, the use of the demand charge was an appropriate method for recovering incurred capacity costs. However, difficulties in recovering incurred capacity costs arise when net metering laws include technologies with high load factors – like CHP systems – that are able to reliably remove load from the grid for great durations but that also need utility service for planned maintenance or unplanned outages. Standby rates have sometimes been used to recover incurred capacity costs that could otherwise not be recovered through regular demand charges, but this practice varies by state.

7.2 Successful Approaches in Net Metering Design

The successful approaches presented in this section were created to address net metering stipulations in Minnesota's newly passed House File 729. The following recommendations were pulled together from successful state practices and recommendations from the Regulatory Assistance Project (RAP) and Interstate Renewable Energy Council (IREC).

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[41] Wan, Yih-hue and H. James Green, "Current experience with net metering programs," Green Power Report, 1998. Accessible at http://apps3.eere.energy.gov/greenpower/resources/pdfs/current_nm.pdf

[42] Applicable for demand billed customers. Residential customers usually pay no demand charges.

Aggregate Caps

Net metering should be offered on a first come first serve basis to all qualified customer-generators who are interconnected and operated in parallel with the grid pursuant to the interconnection agreement provided.

State and utility aggregate generating caps should be removed for net metering customers as they arbitrarily limit potential capacity to a sales percentage. However, if the mechanisms to create a cap exist, the utility must first demonstrate that additional net metering capacity will increase costs on other customers before a cap should be enforced.

Net Excess Generation Credits

The value of net excess generation (NEG) is perhaps the most disputed aspect of net metering policies. On one hand, utilities argue that net metering generation does not displace underlying grid costs or any administrative costs, but only displaces avoided power costs (usually the price of fuel). On the other hand, net metered customers argue that their generation displaces the marginal costs to add new capacity which can usually be quite more expensive than the fuel in existing coal or nuclear plants. Additionally, NEG is delivered at the distribution voltage level which avoids transmission, generation and sometimes distribution related capacity costs.

A central question to the pricing of NEG is the extent that net metered generation can help a utility avoid the need for new capacity. In general, DG customers on a net metering rate offer a product that comes with a service life of twenty years – significant enough to reduce the utility's need for new marginal capacity.[43] Under such a situation NEG should be priced to reflect the long run marginal costs to add new generation resources. Whether the rate of NEG compensation equals the utility's retail rate depends largely on if the retail rate incorporates longer run marginal costs. If the retail rate is lower than the long run marginal costs of added capacity, then the utility and non-generating customers are reaping a greater share of benefits provided by net metering customers. If the converse holds true, then non-generating customers are largely subsidizing net metering customers.

Three states provide examples of successful approaches to crediting NEG of net metered customers (Table 14):

[43] Regulatory Assistance Project, "Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition, (2014), 31.

State	Net Excess Generation (NEG) Policy for Net Metering Customers
California	Customer may choose one of the following: • NEG carried forward to customer's next bill indefinitely. • Customer is financially compensated for NEG each billing period. Compensation calculated with the 12-month average spot market price for the hours of 7 am to 5 pm for the year in which the surplus energy was generated.
Pennsylvania	• NEG is carried forward as a kWh credit. • Customer is financially compensated for any NEG remaining at the end of the year. Compensation is calculated with the "price -to-compare" (includes the generation and transmission components, but not the distribution component, of utility's retail rate).
New York	• NEG for solar PV and wind carried forward as a kWh credit; at the end of a year all NEG is monetized at the utility's avoided rate. NEG for micro CHP is credited at the utility's avoided rate and carried over indefinitely.

Table 14: Successful Approaches to Crediting NEG

Successful approaches in most states credit Net Excess Generation on a 1:1 kWh basis and either roll over credits indefinitely or monetize credits annually at a pre-determined rate (the most common being a market rate, a PURPA avoided rate or a retail rate). The rate at which NEG is monetized should reflect the full costs that net metered generation helps the utility avoid. No matter the method in which net excess generation is credited, those credits should not reduce any fixed monthly customer charges imposed by the utility. For example, net metering credits will only apply to charges that use kWh as the billing determinant.[44] Furthermore, utilities should provide net metering customers service at non-discriminatory rates that are identical in rate structure to the rates these customer would be on but for any on-site generation and net metering implementation.

Standby Requirements

A concern with net metering rates is that they allow customer-generators to avoid capacity and reserve costs which can shift the burden to non-generating customers. Though net metering rates for larger customers (those not on a residential rate) include a demand charge this mechanism might not cover the incurred costs from all net metered generators. The ability of a demand charge to adequately recover utility costs depends largely on the load factor of the generator in question. Load factor refers to the ratio of a generator's average load over their maximum load over a set period of time. For

[44] Interstate Renewable Energy Council, "Net Metering Model Rules," 2009.

example, the yearly load factor of solar PV will be low due to the fact that the sun may not shine during an overcast day in which the customer needs generation. In such an occurrence, the customer must then purchase their full capacity from the utility through the demand charge in the regular rate.

In contrast, a CHP system has a much higher load factor because it is not reliant on an intermittent resource: it can generate night, day and during overcast periods. A higher load factor generator still needs the grid during the occasional outage, but since these outages happen less frequently, the demand charge in the regular rate might not adequately cover the costs to provide capacity during outages. Under such a circumstance, a standby rate may be a warranted approach to recover the utility's capacity related costs. Standby rates should be applied only when demand charges in the regular rate fail at recovering the incurred costs from net metered generators.

The following two tables (Table 15 and Table 16) list 17 states that exempt net metered customers from standby rates:

Net-Metering and Standby Rates for States with CHP Inclusion in Net-Metering Policy:		
State	**Standby**	**Capacity Limit**
Arizona	Arizona Public Service net metering rate EPR-6 stipulates that customer demand be charged using the full-requirements tariff.	• Systems cannot exceed 125% of customer's annual electricity consumption
Florida	At a customer's discretion	• 2 MW
Maine	Exempt	• 660 kW for IOU customers
Maryland	Exempt	• 2 MW • 30 kW for Micro-CHP • Systems cannot exceed 200% of customer's baseline electricity consumption
New York	Exempt	• Solar: 2 MW for non-residential • Wind: 2 MW for non-residential • Micro-CHP: 10 kW (residential only) • Micro-hydroelectric: 2 MW for non-residential
Oklahoma	Exempt	• The lesser of 100 kW or 25,000 kWh/year
Pennsylvania	Exempt	• 5 MW for micro-grid and emergency systems • 3 MW for non-residential • 50 kW for residential
Utah	Exempt	• 2 MW for non-residential

Net-Metering and Standby Rates for States with CHP Inclusion in Net-Metering Policy:		
State	**Standby**	**Capacity Limit**
		• 25 kW for residential
Vermont	Exempt	• 2.2 MW for military systems • 20 kW for micro-CHP • 500 kW for all other systems
Washington	Exempt	• 100 kW

Table 15: Standby Exemption in States that make CHP eligible under Net Metering Rates

Net-Metering and Standby Rates for States that Do Not Include CHP in Net Metering:		
State	**Standby**	**Capacity Limit**
Alaska	Exempt	• 25 kW
California	Exempt	• 1 MW • 5 MW Government or University
Delaware	Exempt	• 500 kW to 2 MW non-residential (varies by utility) • 25 kW residential
Michigan	Exempt	• 150 kW
Nevada	Exempt	The lesser of, • 1 MW • 100% of the customer's annual requirements for electricity
North Carolina	Exemption only for non-residential customers up to 100 kW	• 1 MW
Rhode Island	Exempt	• 5 MW (systems must be sized to not exceed 100% of customer's annual electricity consumption)

Table 16: Standby Exemption in States that do not include CHP under Net Metering Rates

Meter Aggregation

Meter aggregation should be available upon request only when the additional meters are located on the customer's contiguous property and are used to measure electricity only for the customer's requirements. Net metering customers reserve the right to designate the order in which NEG credits shall apply to individual meters.

7.3 Minnesota Net Metering Rules

In 1983, Minnesota instituted one of the nation's first net metering policies that set the generating capacity cap at 40 kilowatts (kW). This size cap existed until 2013 when the Minnesota legislature passed House File 729, which, among other provisions, increased net metering capacity to 1 megawatt (MW) for customers served by IOUs.

Capacity Constraints

Utilities may petition the Minnesota Public Commission to limit additional net metering facilities when the cumulative generation has reached 4% of annual retail electric sales. However, each utility must demonstrate that additional net metering facilities would cause significant rate impacts, require significant reliability measures or raise significant technical issues in order to limit net metering capacity. There is no limit of statewide capacity.

Qualified CHP net metering customers must limit their generation capacity to 120% of their on-site annual electric consumption; however, there are no minimum efficiency requirements for CHP.

Net Excess Generation

Under current Minnesota law, a qualifying net metering facility is defined as an electric generation facility constructed for the purpose of offsetting energy use through the use of renewable energy systems or distributed generation systems with a minimum efficiency of 40%. Eligible distributed generation projects are limited to those that consume natural gas, renewable fuel, or a similarly clean fuel. [45] Net metering customers may elect to receive a credit for any NEG or they may elect to roll over their kilowatt-hour (kWh) credits to future bills. NEG credits for systems sized below 40kW are priced at the "average retail utility energy rate," while credits for larger systems, up to 1 MW, are priced at the avoided costs as defined in the Code of Federal Regulations. At this time, it is unclear if Minnesota law allows customers to receive a check for their net excess generation or if it may only be issued as a credit on an electric bill.

Meter Aggregation

Customers may request meter aggregation if the meters are located on contiguous property owned by the customer requesting the aggregation. The total of all aggregate meters is subject to the size limitation for single meters. Meter aggregation only affects the kilowatt-hour sales and not other

[45] Minnesota, House File 729, Article 9, Section 2, Subdivisions (h)(i)

charges that may apply to multiple meters. An aggregate meter customer may designate the order in which NEG credits apply.

Standby

A concern with Minnesota's new net metering law is that it may allow utilities to impose standby charges on net metering customers whose generating capacity is greater than 100 kW. According to the statute, utilities may petition the public utility commission to establish standby charges for larger net metering customers in order to recover allowable costs. As of writing, all Minnesota utilities have included systems greater than 100 kW under standby provisions. In order to alleviate the financial burden of exceeding the 964 hour standby demand grace period Xcel Energy has included a $5.15 per kW of installed capacity credit for solar units. This credit is applied to the cost of purchasing backup demand when the unit exceeds the grace period.

7.4 Assessment of Minnesota Net Metering Rates

The net metering rates updated though House File 729 are largely in line with successful approaches used in other states and those proposed by the Interstate Renewable Energy Council and the Regulatory Assistance Project. A possible impediment concerns the imposition of standby rates on larger, low load factor net metering customers that might otherwise pay for their capacity through demand charges built into their electric rate. Standby rates for net metering customers with higher load factor generators may be an appropriate method to recover capacity costs. However, HF 729 can be interpreted to require net metering customers with low load factor generator units - who would otherwise pay for their demand through a full-requirements rate - to contract for standby service for a forced outage every time the sun went down or the wind slowed. Since Xcel's current standby rate allows for a maximum of 964 hours of time offline, these customers would be required to pay for both standby service and regular demand service to cover the same capacity. This potential practice of double charging net metering customers for capacity requirements is considered unfair and would significantly hinder Minnesota's ability to achieve its policy goals as stated in House File 729 Article 12. Standby rates can be justified for net metering customers with high availability and reliability, like those running CHP systems if the demand purchased during their infrequent outages doesn't cover capacity related expenses. Since traditional net metering technologies (i.e. solar and wind) go offline more frequently, the regular demand charge within the existing electric rate should provide adequate cost recovery for the utility.

7.5 Recommendations for Net Metering Rates

1. *Standby rates should not be issued when utilities can recover capacity costs through regular rates.* Net Metering rates already include provisions to recuperate the full demand related costs from net metering customers. While net metering rates bill energy consumed or credit energy generated on a net basis they contain no such provision for calculating demand charges; like full-requirement rates, these rates bill customers for their maximum demand placed on the grid. However, not all net metering customers go offline the same amount for time. For those

customers with little or infrequent downtime, standby rates might be an appropriate method to recover capacity related costs. In granting utilities the ability to impose standby charges on net metering customers above 100 kW, the Minnesota Public Utility Commission should be careful not to allow utilities to double charge for capacity cost recovery.

2. *The Net Excess Generation Credit should be the average retail electric rate for all net metering customers.* All net metering customers should be treated equally and be provided the same Net Excess Generation Credit.

7.6 Net Metering Potential

The CHP technical potential for net metering customers was determined by analyzing the number of industrial and commercial facilities with CHP systems sized 1 MW and less. The CHP technical potential for these customers with systems 1 MW and less totaled 242.5 MW for industrial customers and 410.1 MW for commercial sectors, representing 33% of the state's total CHP potential. The commercial sector has a larger potential due to the greater number of facilities where the technical fit of a CHP system would be 1 MW or less, corresponding to the updated net metering threshold. See Appendix C for a detailed list of the net metering technical potential of CHP installations in Minnesota.

The two significant barriers to CHP in the current net metering rates are the inclusion of standby rates and the low NEG credit price. According to HF 729, it is unclear if standby rates will apply to larger net metering customers above 100 kW. Though standby avoidance would certainly help the financial situation of net metering eligible CHP systems it does not decrease any payback windows below the 10 year range.

Without standby rates playing a factor, increasing CHP's economic potential depends largely on the NEG credit price utilities are willing to offer and if they would issue a check instead of a credit on a bill.

Under the current law all net metering customers with a capacity greater than 40 kW shall receive NEG credits priced at the PURPA avoided rate. In their current filing, Xcel proposes to offer these systems $0.02623/kWh for all NEG credits that are a year old.[46] This credit would appear as a line item on the customer's bill instead of a check.

Such a proposal will not increase the economic potential of CHP for two reasons. The first is that a payment of $0.02623/kWh is far too low to be worth the additional fuel needed to generate above a customer's electric load. Most CHP customers would not run their systems for excess generation because the rates are too low to meaningfully reduce the simple payback. The second is that even were the price to suffice, since a customer can never receive a check for NEG there is no way to use NEG credits to reduce system payback.[47]

[46] Minnesota Public Utility Commission Docket E002/M-13-642
[47] It should be noted that most CHP is sized and operated to follow the thermal load. This does mean that there might be times in which the customer needs to generate excess electricity in order to meet an on-site thermal

Net metering rates are designed to aid generation like wind and solar that are dependent on factors outside of human control. When the wind slows down or stops or the sun goes down a customer may use NEG credits against electricity purchased during these times. However, the availability rates for CHP systems are far greater than for wind and solar DG technology. CHP customers on a net metering rate, especially those sized at 120% of their electric load, can easily become net exporters depending on the number of hours they operate their CHP system. Without a greater price and a more direct way to monetize NEG credits, net metering rates do not substantially affect the economic potential of CHP.

requirement or vice-versa. In those circumstances NEG credits could be applied to periods when the generator is not covering the on-site electric load. However, under such a circumstance the customer would still pay the demand charges incurred on the utility.

8. Discussion and Conclusions

Today, there is an installed CHP generating capacity base of 918.5 MW in Minnesota currently ranking the state 5th amongst the 12 Midwest states. Yet there still remains 1,975 MW of unrealized CHP technical potential in the State of which 1,798 MW resides within the four major investor owned utilities of Alliant Energy, Minnesota Power, Otter Tail Power, and Xcel Energy. These figures represent the upward most limits for CHP capacity unrestrained by economic paybacks, operating costs, energy costs or other such costs that factor into a major investment decision. The technical potential figures are useful when gauging the efficacy of policy and rate mitigations to encourage the development CHP projects. This study looked specifically at how standby rates and, to a lesser extent net metering rates, affect the economic potential of CHP projects today and what recommendations, if any, should be considered to reduce the barriers that these factors impose on CHP development.

8.1 Standby Rates

Standby rates in Minnesota have been perceived as a significant barrier to CHP development. Yet with the passage of HF 729 and the approval of Xcel's new standby rates the landscape has changed. However, there are still modifications that can be made to standby rates that would allow CHP generators to avoid a greater portion of their full-requirements rates.

Though the standby suggestions for each utility are somewhat unique, Table 17 outlines the most reoccurring standby modifications for IOUs in Minnesota grouped by functional criteria:

Principle	Analysis and Recommendation
Transparency	*Standby rates should be transparent, concise and easily understandable.* Potential CHP customers should be able to accurately predict future standby charges in order to assess their financial impacts on CHP feasibility.
	Standby usage fees for both demand and energy should reflect time-of-use cost drivers. Time-of-use energy rates send clear price signals as to the cost for the utility to generate needed energy. This would further incentivize the use of off-peak standby services.
Flexibility	*The Forced Outage Rate should be used in the calculation of a customer's reservation charge.* The inclusion of a customer's forced outage rate directly incentivizes standby customers to limit their use of backup service. This further links the use of standby to the price paid to reserve such service creating a strong price signal for customers to run most efficiently. This would also involve the removal of the grace period.
	The standby demand usage fees should only apply during on-peak hours and be charged on a daily basis. This rate design would encourage DG customers to shift their use of standby service to off-peak periods when the marginal cost to provide service is generally much lower. Furthermore, this design would allow customers to save money by reducing the duration of outages.

Principle	Analysis and Recommendation
Economically Efficient Consumption	*Grace periods exempting demand usage fees should be removed where they exist.* Exempting an arbitrary number of hours against demand usage charges sends inaccurate prices signals about the cost to provide this service. The monthly reservation cost providing the grace periods charges for 964 hours of usage no matter if a customer needs that level of service. Standby demand usage should be priced as-used on a daily and preferably an on-peak basis. This method directly ties the standby customer to the costs associated with proving standby service and allows customers to avoid monthly reservation charges by increasing reliability.

Table 17: Standby Rate Policy Recommendations

While the financial effects these modifications might have are largely dependent on customer specific metrics including CHP capacity, operating hours, voltage classification, etc., the suggested modifications should increase the avoided rate of each utility. In order to gauge the effect standby rates have on CHP economic potential, our analytic model analyzed the avoided rates as they currently exist and then as they exist were they to avoid 100% of the full-requirements rate.

8.2 Net Metering Rates

The new net metering rates will help very small CHP systems (<40 kW) to a greater extent than larger systems because the net excess generation credit for smaller systems equals the retail rate while the larger systems only receive the PURPA avoided rate. NEG credits should be the same for all net metering customers. The primary benefit to larger customers, those between 100 kW and 1 MW, would be through standby avoidance; however, it seems that IOUs in Minnesota are currently attempting to include those customers on standby rates. As demonstrated in section 7.2, seventeen states – even those that include CHP as an eligible net metering technology – exempt net metering customers from standby rates. Whether Minnesota utilities should exempt standby rates depends largely on the ability of the demand charge in the regular rate to recover the incurred capacity costs from net metering customers. The load factor of net metered customers provides one way of dividing customers between those requiring standby service to recover incurred costs and those able to stay on the full-requirements rate.

8.3 Economic Potential Analysis

ERC worked in conjunction with ICF International in order to develop the overall economic analysis potential of CHP generating capacity in Minnesota (not including CHP systems installed within electric municipality and cooperative service territories). The ICF model analyzed the impact of avoided rates (as modified through standby and net metering policy recommendations) on simple project payback rates to determine the payback windows for potential CHP installations. The avoided rates used in the economic potential model include the baseline rates and the increased rates from standby and net metering recommendations. Simple paybacks were modeled using current utility electric prices, natural gas rate estimates based on average prices from the EIA for the commercial and industrial sector, and industry average CHP equipment cost and performance characteristics.

From an overall technical potential of 1,798 MW residing in the four major investor owned utilities, the base case modeling results indicated 780 MW of new CHP generating capacity with a simple payback of 10 years or less. Table 18 and Table 19 show the overall economic potential in payback periods compared to the overall technical potential in the Base Case and 100% Avoided Rate Case scenarios. Table 20 and Table 21 provide a more detailed breakout of the economic potential residing in each of the four major investor owned electric utilities for the standby rate scenarios and the baseline natural gas price scenario compared to an increased price in natural gas.

	Payback >10 Years	Payback <10 Years	Payback 0-5 Years	Total Potential, KW
Alliant	52	5	0	57
MN Power	95	141	0	236
Northern States	809	633	0	1,442
Otter Tail	63	0	0	63
Total	1,019	779	0	1,798

Table 18: CHP Economic Potential per Utility (Base Case)

	Payback >10 Years	Payback <10 Years	Payback 0-5 Years	Total Potential, KW
Alliant	52	5	0	57
MN Power	95	141	0	236
Northern States	479	964	0	1,442
Otter Tail	57	6	0	63
Total	682	1,116	0	1,798

Table 19: CHP Economic Potential per Utility (100% Avoided Rate)

	Payback >10 Years	Payback <10 Years	Payback 0-5 Years	Total Potential, KW
Alliant	57	0	0	57
MN Power	236	0	0	236
Northern States	1,442	0	0	1,442
Otter Tail	63	0	0	63
Total	1,798	0	0	1,798

Table 20: CHP Economic Potential per Utility (Base Case & Increased Natural Gas Prices)

	Payback >10 Years	Payback <10 Years	Payback 0-5 years	Total Potential, KW
Alliant	52	5	0	57
MN Power	95	141	0	236
Northern States	809	633	0	1,442
Otter Tail	57	6	0	63
Total	1,013	785	0	1,798

Table 21: CHP Economic Potential per Utility (100% Avoided Rate & Increased Natural Gas Prices)

Due to recent standby modifications and updated net metering policies, these issues are not as significant of a barrier to CHP development as they were previously perceived; however, there still remain opportunities for improvement within the existing rate structures that can greatly impact the overall economic potential of new CHP generating capacity within the State of Minnesota. Standby rates should promote efficiency, fairness, transparency, and system reliability while net metering rates should offer a similar generation credit to all eligible customers and exempt low load factor generators from standby charges.

The economic potential analysis resulting in the various payback periods only factored varied avoided rates and the price of natural gas. It should be noted though that the modeling results showed no CHP projects would experience a payback less than 5 years when modeling improved standby rates. This would indicate that standby rates are not the sole barrier to CHP development in the State of Minnesota for policy makers to consider. Like many states, standby rates are one of several barriers that impair the development of CHP projects.

The economic potential analysis only factored varied avoided rates and the price of natural gas. Other factors that should be considered when developing CHP projects that can positively impact project simple paybacks and overall economic potential are, but not limited to:

- Grid Congestion due to environmental pressures on coal fired utility power plants shutting down and the ability of CHP systems to relieve grid constrain by providing generation in specified locations of the utility grid.
- Energy Resiliency and the capability of properly installed CHP systems to maintain facility operations due to grid outages from man-made disasters (i.e. terrorist attacks) and natural disasters (i.e. heavy rain and snow storms, tornadoes, etc.).
- Microgrid advancements and the development of district energy systems with CHP centered as the primary generation technology.

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Appendix A – CHP Technical Potential Methodology

This section describes the methodology for estimating the technical market potential for combined heat and power (CHP) in the industrial and commercial/institutional market sectors. Two different types of CHP markets (traditional CHP and combined cooling heating and power) were included in the evaluation of technical potential. Both of these markets were evaluated for high load factor (80% and above) and low load factor (51%) applications resulting in four distinct market segments that are analyzed.

Traditional CHP – Heating Only

Traditional CHP electrical output is produced to meet all or a portion of the base load for a facility and the thermal energy is used to provide steam or hot water. Depending on the type of facility, the appropriate sizing could be either electric or thermal limited. Industrial facilities often have “excess” thermal load compared to their on-site electric load. Commercial facilities almost always have excess electric load compared to their thermal load. Two sub-categories were considered:

- High load factor applications: This market provides for continuous or nearly continuous operation. It includes all industrial applications and round-the-clock commercial/institutional operations such colleges, hospitals, hotels, and prisons.

- Low load factor applications: Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500 to 5,000 hours per year. This sector includes applications such as schools, and laundries.

CHP with Heating and Cooling

All or a portion of the thermal output of a CHP system can be converted to air conditioning or refrigeration with the addition of a thermally activated cooling system. This type of system can potentially open up the benefits of CHP to facilities that do not have the year-round thermal load to support a traditional CHP system. A typical system would provide the annual hot water load, a portion of the space heating load in the winter months and a portion of the cooling load in during the summer months. Two sub-categories were considered:

- Low load factor applications: These represent markets that otherwise could not support CHP due to a lack of thermal load. This sector includes applications such as commercial office buildings.

- Incremental high load factor applications: These markets represent round-the-clock commercial/institutional facilities that could support traditional CHP, but with cooling, incremental capacity could be added while maintaining a high level of use of the thermal energy from the CHP system.

All of the market segments in this category are also included in the high load factor traditional market segment, so only the incremental capacity for these markets is added to the overall totals.

The estimation of technical market potential consists of the following elements:

- Identification of applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications were identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities.

- Quantification of the number and size distribution of target applications. Several data sources were used to identify the number of applications by sector that meets the thermal and electric load requirements for CHP.

- Estimation of CHP potential in terms of megawatt (MW) capacity. Total CHP potential is then derived for each target application based on the number of target facilities in each size category and sizing criteria appropriate for each sector.

- Subtraction of existing CHP from the identified sites to determine the remaining technical market potential.

The technical market potential does not consider screening for economic rate of return, or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical potential as outlined is useful in understanding the potential size and size distribution of the target CHP markets in the state. Identifying technical market potential is a preliminary step in the assessment of economic potential. The basic approach to developing the technical potential is described below:

- Identify existing CHP in the state. The analysis of CHP potential starts with the identification of existing CHP. The U.S. currently has 4,100 CHP sites totaling 81.8 GW of capacity. Of this existing CHP capacity, 31% of the sites and 80% of the capacity are in the industrial sector. This existing CHP capacity is deducted from any identified technical potential.

- Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications were identified based on reviewing the electric and thermal energy (heating and cooling) consumption data for various building types and industrial facilities. Data sources include the DOE EIA Commercial Buildings Energy Consumption Survey (CBECS), the DOE Manufacturing Energy Consumption Survey (MECS) and various market summaries developed by DOE. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.

- Quantify the number and size distribution of target applications. Once applications that could technically support CHP were identified, the Hoovers database from Dun & Bradstreet and the Major Industrial Plant Database (MIPD) from IHS were used to identify potential CHP sites by SIC code or application, and location. The Hoovers database is based on the Dun & Bradstreet financial listings and includes information on economic activity (8 digit SIC), location (metropolitan area, county, electric utility service area, state) and size (employees) for commercial, institutional and industrial facilities. In addition, for select SICs limited energy consumption information (electric and gas consumption, electric and gas expenditures) is provided based on data from Wharton Econometric Forecasting (WEFA). MIPD has detailed energy and process data for 16,000 of the largest energy consuming industrial plants in the United States. The Hoovers database and MIPD were used to identify the number of facilities in target CHP applications and to group them into size categories based on average electric demand in kilowatt-hours.

Total CHP potential is then derived for each target application based on the number of target facilities in each size category. It was assumed that the CHP system would be sized to meet the average site electric demand for the target applications unless thermal loads (heating and cooling) limited electric capacity. There are two distinct applications and two levels of annual load making for four market segments in all. In traditional CHP, the thermal energy is recovered and used for heating, process steam, or hot water. In cooling CHP, the system provides both heating and cooling needs for the facility. High load factor applications are assumed to operate at 80% load factor and above; low load factor applications operate at an assumed average of 4500 hours per year (51%) load factor. The high load factor cooling applications are also applications for traditional CHP, though the cooling applications have 25-30% more capacity than traditional.

Appendix B – CHP Technical Potential by Utility and Sector

B – 1: Xcel Energy – Northern States

Industrial Sector

SIC	Application	50 - 500 KW		500 kW - 1 MW		1 - 5 MW		5 - 20 MW		> 20 MW		Total	
		Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity
20	Food	125	23.4	23	15.5	33	69.0	5	35.0	2	71.9	188	214.9
22	Textiles	12	2.4	1	0.8	0	0.0	0	0.0	0	0.0	13	3.2
24	Lumber and Wood	79	12.2	9	6.7	5	7.0	1	6.2	0	0.0	94	32.2
25	Furniture	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
26	Paper	54	11.9	23	15.2	10	20.3	3	31.3	1	41.3	91	120.0
27	Printing	11	1.5	1	0.7	0	0.0	0	0.0	0	0.0	12	2.2
28	Chemicals	120	20.3	26	18.1	33	78.2	11	76.2	0	0.0	190	192.7
29	Petroleum Refining	0	0.0	2	1.4	1	3.5	1	6.5	2	203.0	6	214.4
30	Rubber/Misc. Plastics	138	20.5	12	7.9	1	1.9	0	0.0	0	0.0	151	30.2
32	Stone/Clay/Glass	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
33	Primary Metals	24	5.7	7	4.9	6	15.3	1	6.5	0	0.0	38	32.4
34	Fabricated Metals	52	5.6	1	0.5	0	0.0	0	0.0	0	0.0	53	6.1
35	Machinery/Computer Equip	9	1.1	0	0.0	1	1.3	0	0.0	0	0.0	10	2.4
37	Transportation Equip.	25	3.7	3	1.8	3	7.2	1	8.3	0	0.0	32	21.0
38	Instruments	3	0.2	0	0.0	0	0.0	0	0.0	0	0.0	3	0.2
39	Misc. Manufacturing	8	0.9	0	0.0	1	1.3	0	0.0	0	0.0	9	2.2
	Total	**660**	**109.4**	**108**	**73.5**	**94**	**205.0**	**23**	**170.0**	**5**	**316.2**	**890**	**874.1**

Table 22: Xcel Energy Industrial Sector CHP Technical Potential

Commercial Sector

SIC	Application	50 - 500 KW Sites	50 - 500 KW Capacity	500 kW - 1 MW Sites	500 kW - 1 MW Capacity	1 - 5 MW Sites	1 - 5 MW Capacity	5 - 20 MW Sites	5 - 20 MW Capacity	> 20 MW Sites	> 20 MW Capacity	Total Sites	Total Capacity
43	Post Offices	3	0.3	0	0.0	1	1.1	0	0.0	0	0.0	4	1.4
52	Retail	298	31.8	9	6.1	1	1.3	0	0.0	0	0.0	308	39.3
4222	Refrigerated Warehouses	11	1.7	2	1.1	0	0.0	1	6.7	0	0.0	14	9.5
4581	Airports	0	0.0	0	0.0	0	0.0	1	19.1	0	0.0	1	19.1
4952	Water Treatment	7	0.6	0	0.0	0	0.0	0	0.0	0	0.0	7	0.6
5411	Food Stores	125	28.7	17	10.6	0	0.0	0	0.0	0	0.0	142	39.4
5812	Restaurants	402	42.1	0	0.0	1	1.4	0	0.0	0	0.0	403	43.4
6512	Commercial Buildings	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
6513	Multifamily Buildings	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
7011	Hotels	171	25.3	11	7.0	5	7.6	1	7.8	0	0.0	188	47.8
7211	Laundries	13	2.2	4	2.7	0	0.0	0	0.0	0	0.0	17	4.9
7374	Data Centers	32	5.7	3	2.0	5	9.7	1	6.1	0	0.0	41	23.5
7542	Car Washes	24	1.7	0	0.0	0	0.0	0	0.0	0	0.0	24	1.7
7832	Movie Theaters	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
7991	Health Clubs	39	5.2	4	2.3	2	4.0	0	0.0	0	0.0	45	11.5
7997	Golf/Country Clubs	90	9.9	2	1.0	0	0.0	0	0.0	0	0.0	92	10.9
8051	Nursing Homes	180	24.9	7	4.3	4	5.4	0	0.0	0	0.0	191	34.6
8062	Hospitals	34	7.0	18	12.5	21	45.8	1	5.8	0	0.0	74	71.1
8211	Schools	181	13.9	0	0.0	0	0.0	0	0.0	0	0.0	181	13.9
8221	College/Univ	45	8.3	13	10.0	16	35.1	9	80.3	1	21.0	84	154.7
8412	Museums	7	1.3	1	1.0	0	0.0	0	0.0	0	0.0	8	2.2
9100	Government Buildings	137	20.7	13	10.0	9	12.8	0	0.0	0	0.0	159	43.5
9223	Prisons	4	0.4	1	0.9	8	17.0	0	0.0	0	0.0	13	18.2
9711	Military	5	0.9	0	0.0	2	5.1	0	0.0	0	0.0	7	6.1
	Total	**1,809**	**232.6**	**105**	**71.5**	**75**	**146.3**	**14**	**125.8**	**1**	**21.0**	**2,004**	**597.2**

Table 23: Table 21: Xcel Energy Commercial Sector CHP Technical Potential

B – 2: Alliant Energy

Industrial Sector

SIC	Application	50 - 500 KW		500 kW - 1 MW		1 - 5 MW		5 - 20 MW		> 20 MW		Total	
		Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity
20	Food	6	1.5	1	0.7	4	8.0	0	0.0	0	0.0	11	10.2
22	Textiles	0	0.0	0	0.0	1	1.8	0	0.0	0	0.0	1	1.8
24	Lumber and Wood	2	0.2	0	0.0	1	1.2	0	0.0	0	0.0	3	1.3
25	Furniture	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
26	Paper	2	0.4	1	0.8	0	0.0	0	0.0	0	0.0	3	1.2
27	Printing	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
28	Chemicals	15	2.6	1	0.9	8	26.2	1	5.2	0	0.0	25	35.0
29	Petroleum Refining	0	0.0	1	0.7	0	0.0	0	0.0	0	0.0	1	0.7
30	Rubber/Misc. Plastics	4	0.6	0	0.0	0	0.0	0	0.0	0	0.0	4	0.6
32	Stone/Clay/Glass	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
33	Primary Metals	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
34	Fabricated Metals	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
35	Machinery/Computer Equip	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
37	Transportation Equip.	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
38	Instruments	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
39	Misc. Manufacturing	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
	Total	**31**	**5.5**	**4**	**3.2**	**14**	**37.1**	**1**	**5.2**	**0**	**0.0**	**50**	**51.0**

Table 24: Alliant Energy Industrial Sector CHP Technical Potential

Commercial Sector

SIC	Application	50 - 500 KW		500 kW - 1 MW		1 - 5 MW		5 - 20 MW		> 20 MW		Total	
		Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity
43	Post Offices	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
52	Retail	3	0.3	0	0.0	0	0.0	0	0.0	0	0.0	3	0.3
4222	Refrigerated Warehouses	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
4581	Airports	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
4952	Water Treatment	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
5411	Food Stores	2	0.4	1	0.6	0	0.0	0	0.0	0	0.0	3	1.0
5812	Restaurants	2	0.2	0	0.0	0	0.0	0	0.0	0	0.0	2	0.2
6512	Commercial Buildings	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
6513	Multifamily Buildings	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
7011	Hotels	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
7211	Laundries	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
7374	Data Centers	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
7542	Car Washes	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
7832	Movie Theaters	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
7991	Health Clubs	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
7997	Golf/Country Clubs	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
8051	Nursing Homes	22	2.3	0	0.0	0	0.0	0	0.0	0	0.0	22	2.3
8062	Hospitals	1	0.2	1	0.9	0	0.0	0	0.0	0	0.0	2	1.0
8211	Schools	2	0.1	0	0.0	0	0.0	0	0.0	0	0.0	2	0.1
8221	College/University	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
8412	Museums	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
9100	Government Buildings	7	0.9	0	0.0	0	0.0	0	0.0	0	0.0	7	0.9
9223	Prisons	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
9711	Military	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
	Total	**41**	**4.5**	**2**	**1.5**	**0**	**0.0**	**0**	**0.0**	**0**	**0.0**	**43**	**5.9**

Table 25: Alliant Energy Commercial Sector CHP Technical Potential

B – 3: Minnesota Power

Industrial Sector

SIC	Application	50 - 500 KW		500 kW - 1 MW		1 - 5 MW		5 - 20 MW		> 20 MW		Total	
		Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity
20	Food	5	1.0	1	0.6	1	1.6	0	0.0	0	0.0	7	3.1
22	Textiles	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
24	Lumber and Wood	27	5.0	2	1.5	3	4.8	2	21.0	0	0.0	34	32.2
25	Furniture	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
26	Paper	3	0.5	0	0.0	2	6.1	4	32.4	2	81.2	11	120.1
27	Printing	2	0.3	1	0.5	0	0.0	0	0.0	0	0.0	3	0.9
28	Chemicals	5	1.0	0	0.0	4	8.3	0	0.0	0	0.0	9	9.3
29	Petroleum Refining	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
30	Rubber/Misc. Plastics	11	2.0	0	0.0	0	0.0	0	0.0	0	0.0	11	2.0
32	Stone/Clay/Glass	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
33	Primary Metals	4	0.7	1	0.9	1	1.4	0	0.0	0	0.0	6	3.0
34	Fabricated Metals	3	0.7	0	0.0	0	0.0	0	0.0	0	0.0	3	0.7
35	Machinery/Computer Equip	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
37	Transportation Equip.	4	0.7	1	0.7	0	0.0	0	0.0	0	0.0	5	1.4
38	Instruments	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
39	Misc. Manufacturing	1	0.3	0	0.0	0	0.0	0	0.0	0	0.0	1	0.3
	Total	**66**	**12.3**	**6**	**4.2**	**11**	**22.2**	**6**	**53.4**	**2**	**81.2**	**91**	**173.1**

Table 26: Minnesota Power Industrial Sector CHP Technical Potential

Commercial Sector

SIC	Application	50-500 kW Sites	50-500 kW MW	500-1 MW Sites	500-1 MW (MW)	1-5 MW Sites	1-5 MW (MW)	5-20 MW Sites	5-20 MW (MW)	>20 MW Sites	>20 MW (MW)	Total Sites	Total MW
43	Post Offices	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
52	Retail	28	2.9	1	0.5	1	1.1	0	0.0	0	0.0	30	4.5
4222	Refrigerated Warehouses	2	0.1	0	0.0	0	0.0	0	0.0	0	0.0	2	0.1
4581	Airports	1	0.4	0	0.0	0	0.0	0	0.0	0	0.0	1	0.4
4952	Water Treatment	2	0.4	0	0.0	1	2.8	0	0.0	0	0.0	3	3.2
5411	Food Stores	26	4.1	0	0.0	0	0.0	0	0.0	0	0.0	26	4.1
5812	Restaurants	22	1.9	0	0.0	0	0.0	0	0.0	0	0.0	22	1.9
6512	Commercial Buildings	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
6513	Multifamily Buildings	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
7011	Hotels	41	5.9	1	0.7	1	1.5	0	0.0	0	0.0	43	8.1
7211	Laundries	2	0.2	0	0.0	0	0.0	0	0.0	0	0.0	2	0.2
7374	Data Centers	2	0.1	1	0.5	0	0.0	0	0.0	0	0.0	3	0.6
7542	Car Washes	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
7832	Movie Theaters	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
7991	Health Clubs	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
7997	Golf/Country Clubs	13	1.1	0	0.0	0	0.0	0	0.0	0	0.0	13	1.1
8051	Nursing Homes	27	3.6	0	0.0	0	0.0	0	0.0	0	0.0	27	3.6
8062	Hospitals	13	3.0	5	3.3	6	8.7	0	0.0	0	0.0	24	14.9
8211	Schools	11	0.8	0	0.0	0	0.0	0	0.0	0	0.0	11	0.8
8221	College/University	6	1.5	3	2.1	1	1.3	1	6.7	0	0.0	11	11.6
8412	Museums	2	0.2	0	0.0	0	0.0	0	0.0	0	0.0	2	0.2
9100	Government Buildings	19	2.8	2	1.5	0	0.0	0	0.0	0	0.0	21	4.3
9223	Prisons	3	0.3	0	0.0	2	3.9	0	0.0	0	0.0	5	4.2
9711	Military	0	0.0	1	0.5	0	0.0	0	0.0	0	0.0	1	0.5
	Total	**222**	**29.5**	**14**	**9.2**	**12**	**19.2**	**1**	**6.7**	**0**	**0.0**	**249**	**64.5**

Table 27: Minnesota Power Commercial Sector CHP Technical Potential

B – 4: Otter Tail Electric

Industrial Sector

SIC	Application	50 - 500 KW		500 kW - 1 MW		1 - 5 MW		5 - 20 MW		> 20 MW		Total	
		Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity
20	Food	9	1.4	4	3.2	2	3.4	0	0.0	0	0.0	15	8.0
22	Textiles	1	0.2	0	0.0	0	0.0	0	0.0	0	0.0	1	0.2
24	Lumber and Wood	11	2.2	3	2.0	1	1.0	1	5.7	0	0.0	16	10.9
25	Furniture	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
26	Paper	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
27	Printing	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
28	Chemicals	10	1.4	2	1.3	1	1.9	0	0.0	0	0.0	13	4.6
29	Petroleum Refining	0	0.0	1	0.7	0	0.0	0	0.0	0	0.0	1	0.7
30	Rubber/Misc. Plastics	2	0.2	0	0.0	0	0.0	0	0.0	0	0.0	2	0.2
32	Stone/Clay/Glass	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
33	Primary Metals	0	0.0	0	0.0	1	1.8	0	0.0	0	0.0	1	1.8
34	Fabricated Metals	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
35	Machinery/Computer Equip	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
37	Transportation Equip.	3	0.4	0	0.0	0	0.0	0	0.0	0	0.0	3	0.4
38	Instruments	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
39	Misc. Manufacturing	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
	Total	**37**	**5.9**	**10**	**7.2**	**5**	**8.2**	**1**	**5.7**	**0**	**0.0**	**53**	**27.0**

Table 28: Otter Tail Electric Industrial Sector CHP Technical Potential

Commercial Sector

SIC	Application	50 - 500 KW		500 kW - 1 MW		1 - 5 MW		5 - 20 MW		> 20 MW		Total	
		Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity
43	Post Offices	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
52	Retail	10	1.3	0	0.0	0	0.0	0	0.0	0	0.0	10	1.3
4222	Refrigerated Warehouses	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
4581	Airports	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
4952	Water Treatment	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
5411	Food Stores	10	1.8	0	0.0	0	0.0	0	0.0	0	0.0	10	1.8
5812	Restaurants	9	0.8	0	0.0	0	0.0	0	0.0	0	0.0	9	0.8
6512	Commercial Buildings	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
6513	Multifamily Buildings	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
7011	Hotels	8	0.9	0	0.0	1	2.3	0	0.0	0	0.0	9	3.2
7211	Laundries	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
7374	Data Centers	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
7542	Car Washes	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
7832	Movie Theaters	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
7991	Health Clubs	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
7997	Golf/Country Clubs	4	0.4	0	0.0	0	0.0	0	0.0	0	0.0	4	0.4
8051	Nursing Homes	28	2.9	2	1.8	0	0.0	0	0.0	0	0.0	30	4.7
8062	Hospitals	12	2.8	5	3.0	1	1.4	0	0.0	0	0.0	18	7.2
8211	Schools	3	0.2	0	0.0	0	0.0	0	0.0	0	0.0	3	0.2
8221	College/University	2	0.5	1	0.8	4	8.7	0	0.0	0	0.0	7	10.0
8412	Museums	1	0.2	0	0.0	0	0.0	0	0.0	0	0.0	1	0.2
9100	Government Buildings	15	2.1	1	1.0	0	0.0	0	0.0	0	0.0	16	3.1
9223	Prisons	0	0.0	0	0.0	1	3.0	0	0.0	0	0.0	1	3.0
9711	Military	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
	Total	**106**	**14.3**	**9**	**6.6**	**7**	**15.3**	**0**	**0.0**	**0**	**0.0**	**122**	**36.2**

Table 29: Otter Tail Electric Commercial Sector CHP Technical Potential

B – 5: Municipalities / Cooperatives

Industrial Sector

SIC	Application	50 - 500 KW Sites	50 - 500 KW Capacity	500 kW - 1 MW Sites	500 kW - 1 MW Capacity	1 - 5 MW Sites	1 - 5 MW Capacity	5 - 20 MW Sites	5 - 20 MW Capacity	> 20 MW Sites	> 20 MW Capacity	Total Sites	Total Capacity
20	Food	15	3.1	3	2.3	7	15.3	0	0.0	0	0.0	25	20.7
22	Textiles	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
24	Lumber and Wood	18	3.8	3	2.3	2	3.0	1	6.5	0	0.0	24	15.4
25	Furniture	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
26	Paper	0	0.0	1	0.8	2	4.1	1	8.4	1	20.7	5	34.0
27	Printing	5	0.9	0	0.0	0	0.0	0	0.0	0	0.0	5	0.9
28	Chemicals	10	2.1	1	0.5	7	20.2	0	0.0	0	0.0	18	22.8
29	Petroleum Refining	0	0.0	1	0.6	0	0.0	0	0.0	0	0.0	1	0.6
30	Rubber/Misc. Plastics	10	1.9	1	0.8	0	0.0	0	0.0	0	0.0	11	2.6
32	Stone/Clay/Glass	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
33	Primary Metals	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
34	Fabricated Metals	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
35	Machinery/Computer Equip	1	0.4	0	0.0	0	0.0	0	0.0	0	0.0	1	0.4
37	Transportation Equip.	4	0.5	2	1.4	1	1.9	0	0.0	0	0.0	7	3.9
38	Instruments	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
39	Misc. Manufacturing	2	0.2	0	0.0	0	0.0	0	0.0	0	0.0	2	0.2
	Total	**66**	**12.8**	**12**	**8.7**	**19**	**44.5**	**2**	**14.8**	**1**	**20.7**	**100**	**101.6**

Table 30: Muni/Coop Industrial Sector CHP Technical Potential

Commercial Sector

SIC	Application	50 - 500 KW		500 kW - 1 MW		1 - 5 MW		5 - 20 MW		> 20 MW		Total	
		Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity	Sites	Capacity
43	Post Offices	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
52	Retail	32	3.8	0	0.0	0	0.0	0	0.0	0	0.0	32	3.8
4222	Refrigerated Warehouses	1	0.2	0	0.0	0	0.0	0	0.0	0	0.0	1	0.2
4581	Airports	1	0.3	0	0.0	0	0.0	0	0.0	0	0.0	1	0.3
4952	Water Treatment	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
5411	Food Stores	15	3.2	4	2.6	0	0.0	0	0.0	0	0.0	19	5.7
5812	Restaurants	25	2.2	0	0.0	0	0.0	0	0.0	0	0.0	25	2.2
6512	Commercial Buildings	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
6513	Multifamily Buildings	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
7011	Hotels	32	4.0	1	0.5	0	0.0	0	0.0	0	0.0	33	4.5
7211	Laundries	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
7374	Data Centers	1	0.1	0	0.0	0	0.0	0	0.0	0	0.0	1	0.1
7542	Car Washes	2	0.1	0	0.0	0	0.0	0	0.0	0	0.0	2	0.1
7832	Movie Theaters	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
7991	Health Clubs	2	0.2	0	0.0	0	0.0	0	0.0	0	0.0	2	0.2
7997	Golf/Country Clubs	7	0.6	0	0.0	0	0.0	0	0.0	0	0.0	7	0.6
8051	Nursing Homes	38	4.3	0	0.0	0	0.0	0	0.0	0	0.0	38	4.3
8062	Hospitals	22	4.0	7	4.5	0	0.0	0	0.0	0	0.0	29	8.6
8211	Schools	13	0.9	0	0.0	0	0.0	0	0.0	0	0.0	13	0.9
8221	College/University	5	0.8	2	1.4	1	1.2	0	0.0	0	0.0	8	3.5
8412	Museums	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
9100	Government Buildings	26	4.2	3	2.4	1	1.1	0	0.0	0	0.0	30	7.7
9223	Prisons	0	0.0	0	0.0	1	1.8	0	0.0	0	0.0	1	1.8
9711	Military	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
	Total	**225**	**29.0**	**17**	**11.5**	**3**	**4.2**	**0**	**0.0**	**0**	**0.0**	**245**	**44.7**

Table 31: Muni/Coop Commercial Sector CHP Technical Potential

Appendix C – Net Metering Technical Potential

SIC	Application	Total Sites	Total MW	Total MWh
20	Food	246	52.6	394,441
22	Textiles	16	3.5	26,219
24	Lumber and Wood	171	35.8	268,418
26	Paper	110	29.7	222,555
27	Printing	20	4.0	29,910
28	Chemicals	255	48.2	361,125
29	Petroleum Refining	9	3.4	25,779
30	Rubber/Misc Plastics	179	33.8	253,438
33	Primary Metals	45	12.2	91,411
34	Fabricated Metals	59	7.1	53,080
35	Machinery/Computer Equip	12	1.6	11,906
37	Transportation Equip.	47	9.2	69,057
38	Instruments	3	0.2	1,233
39	Misc. Manufacturing	12	1.4	10,261
	Industrial Sector Total	**1,184**	**242.5**	**1,818,834**
43	Post Offices	4	0.4	1,933
52	Retail	381.0	46.7	210,353
4222	Refrigerated Warehouses	17.0	3.1	23,513
4581	Airports	3.0	0.7	3,087
4952	Water Treatment	11.0	1.1	8,360
5411	Food Stores	200.0	52.1	234,246
5812	Restaurants	460.0	47.2	212,214
7011	Hotels	265.0	44.4	332,912
7211	Laundries	21.0	5.3	23,809
7374	Data Centers	39.0	8.4	63,270
7542	Car Washes	28.0	1.9	8,744
7832	Movie Theaters	1.0	0.1	273
7991	Health Clubs	46.0	7.8	35,154
7997	Golf/Country Clubs	117.0	13.1	58,807
8051	Nursing Homes	304.0	44.1	330,527
8062	Hospitals	118.0	41.2	308,976
8211	Schools	210.0	15.9	71,502
8221	College/Univ	77.0	25.5	191,544
8412	Museums	11.0	2.6	11,543
9100	Government Buildings	223.0	45.5	204,880
9223	Prisons	8.0	1.5	11,551
9711	Military	6.0	1.5	10,962
	Commercial Sector Total	**2,550**	**410.1**	**2,358,160**

Table 32: Net Metering Technical Potential

Appendix D – Economic Payback Model Assumptions

D –1: Electric Rates

High Load Factor Retail Rates ($/kWh)

Utility	Year	50 kW-500 kW	500 kW -1 MW	1-5 MW	5-20 MW	>20 MW
Alliant	2013	0.0615	0.0607	0.0587	0.0585	0.0585
MN Power	2013	0.0823	0.0822	0.0668	0.0668	0.0638
Xcel Energy	2013	0.0672	0.0651	0.0631	0.0605	0.0596
Otter Tail	2013	0.0753	0.0725	0.0562	0.0542	0.0496
Alliant	2013 to 2017	0.0623	0.0615	0.0596	0.0593	0.0593
MN Power	2013 to 2017	0.0834	0.0834	0.0678	0.0677	0.0647
Xcel Energy	2013 to 2017	0.0682	0.0661	0.0640	0.0613	0.0604
Otter Tail	2013 to 2017	0.0764	0.0735	0.0570	0.0549	0.0503
Alliant	2018 to 2022	0.0646	0.0637	0.0617	0.0614	0.0614
MN Power	2018 to 2022	0.0864	0.0864	0.0702	0.0701	0.0669
Xcel Energy	2018 to 2022	0.0706	0.0684	0.0662	0.0635	0.0626
Otter Tail	2018 to 2022	0.0791	0.0761	0.0590	0.0569	0.0521
Alliant	2023 to 2027	0.0668	0.0660	0.0639	0.0636	0.0636
MN Power	2023 to 2027	0.0895	0.0894	0.0727	0.0726	0.0693
Xcel Energy	2023 to 2027	0.0731	0.0708	0.0686	0.0658	0.0648
Otter Tail	2023 to 2027	0.0819	0.0788	0.0611	0.0589	0.0540
Alliant	2028 to 2032	0.0692	0.0683	0.0661	0.0659	0.0659
MN Power	2028 to 2032	0.0926	0.0926	0.0752	0.0752	0.0718
Xcel Energy	2028 to 2032	0.0757	0.0734	0.0710	0.0681	0.0671
Otter Tail	2028 to 2032	0.0848	0.0816	0.0633	0.0610	0.0559

Table 33: High Load Factor Electric Rate Model Inputs

Low Load Factor Retail Rates ($/kWh)

Utility	Year	50 kW-500 kW	500 kW -1 MW	1-5 MW	5-20 MW	>20 MW
Alliant	2013	0.0771	0.0755	0.0725	0.0714	0.0713
MN Power	2013	0.0903	0.0902	0.0772	0.0770	0.0740
Xcel Energy	2013	0.0753	0.0878	0.0847	0.0812	0.0795
Otter Tail	2013	0.0776	0.0743	0.0648	0.0749	0.0677
Alliant	2013 to 2017	0.0782	0.0766	0.0735	0.0724	0.0723
MN Power	2013 to 2017	0.0916	0.0915	0.0783	0.0781	0.0751
Xcel Energy	2013 to 2017	0.0764	0.0891	0.0859	0.0824	0.0807
Otter Tail	2013 to 2017	0.0787	0.0754	0.0658	0.0760	0.0687
Alliant	2018 to 2022	0.0810	0.0793	0.0761	0.0749	0.0749
MN Power	2018 to 2022	0.0948	0.0948	0.0810	0.0809	0.0778
Xcel Energy	2018 to 2022	0.0791	0.0922	0.0889	0.0853	0.0835
Otter Tail	2018 to 2022	0.0814	0.0781	0.0681	0.0787	0.0711
Alliant	2023 to 2027	0.0838	0.0821	0.0788	0.0776	0.0775
MN Power	2023 to 2027	0.0982	0.0981	0.0839	0.0838	0.0805
Xcel Energy	2023 to 2027	0.0819	0.0955	0.0921	0.0883	0.0865
Otter Tail	2023 to 2027	0.0843	0.0808	0.0705	0.0815	0.0736
Alliant	2028 to 2032	0.0868	0.0850	0.0816	0.0803	0.0803
MN Power	2028 to 2032	0.1017	0.1016	0.0869	0.0868	0.0834
Xcel Energy	2028 to 2032	0.0848	0.0989	0.0953	0.0915	0.0896
Otter Tail	2028 to 2032	0.0873	0.0837	0.0730	0.0844	0.0763

Table 34: Low Load Factor Electric Rate Model Inputs

D – 2: Natural Gas Prices

Low Estimate from EIA ($/MMBtu)

	Boiler Load (Therms/day)					CHP Load (Therms/day)				
	354	**660**	**2,419**	**8,815**	**35,206**	**667**	**1,499**	**5,645**	**21,639**	**81,429**
2013 to 2017	$5.00	$5.00	$4.50	$4.50	$4.50	$5.00	$5.00	$4.50	$4.50	$4.50
2013 to 2017	$5.00	$5.00	$4.50	$4.50	$4.50	$5.00	$5.00	$4.50	$4.50	$4.50
2013 to 2017	$5.00	$5.00	$4.50	$4.50	$4.50	$5.00	$5.00	$4.50	$4.50	$4.50
2013 to 2017	$5.00	$5.00	$4.50	$4.50	$4.50	$5.00	$5.00	$4.50	$4.50	$4.50
2018 to 2022	$5.31	$5.31	$4.78	$4.78	$4.78	$5.31	$5.31	$4.78	$4.78	$4.78
2018 to 2022	$5.31	$5.31	$4.78	$4.78	$4.78	$5.31	$5.31	$4.78	$4.78	$4.78
2018 to 2022	$5.31	$5.31	$4.78	$4.78	$4.78	$5.31	$5.31	$4.78	$4.78	$4.78
2018 to 2022	$5.31	$5.31	$4.78	$4.78	$4.78	$5.31	$5.31	$4.78	$4.78	$4.78
2023 to 2027	$5.63	$5.63	$5.07	$5.07	$5.07	$5.63	$5.63	$5.07	$5.07	$5.07
2023 to 2027	$5.63	$5.63	$5.07	$5.07	$5.07	$5.63	$5.63	$5.07	$5.07	$5.07
2023 to 2027	$5.63	$5.63	$5.07	$5.07	$5.07	$5.63	$5.63	$5.07	$5.07	$5.07
2023 to 2027	$5.63	$5.63	$5.07	$5.07	$5.07	$5.63	$5.63	$5.07	$5.07	$5.07
2028 to 2032	$5.98	$5.98	$5.38	$5.38	$5.38	$5.98	$5.98	$5.38	$5.38	$5.38
2028 to 2032	$5.98	$5.98	$5.38	$5.38	$5.38	$5.98	$5.98	$5.38	$5.38	$5.38
2028 to 2032	$5.98	$5.98	$5.38	$5.38	$5.38	$5.98	$5.98	$5.38	$5.38	$5.38
2028 to 2032	$5.98	$5.98	$5.38	$5.38	$5.38	$5.98	$5.98	$5.38	$5.38	$5.38

Table 35: Low EIA Natural Gas Price Estimates

High Estimate from EIA ($/MMBtu)

	Boiler Load (Therms/day)					CHP Load (Therms/day)				
	354	**660**	**2,419**	**8,815**	**35,206**	**667**	**1,499**	**5,645**	**21,639**	**81,429**
2013 to 2017	$6.50	$6.50	$6.00	$6.00	$6.00	$6.50	$6.50	$6.00	$6.00	$6.00
2013 to 2017	$6.50	$6.50	$6.00	$6.00	$6.00	$6.50	$6.50	$6.00	$6.00	$6.00
2013 to 2017	$6.50	$6.50	$6.00	$6.00	$6.00	$6.50	$6.50	$6.00	$6.00	$6.00
2013 to 2017	$6.50	$6.50	$6.00	$6.00	$6.00	$6.50	$6.50	$6.00	$6.00	$6.00
2018 to 2022	$6.90	$6.90	$6.37	$6.37	$6.37	$6.90	$6.90	$6.37	$6.37	$6.37
2018 to 2022	$6.90	$6.90	$6.37	$6.37	$6.37	$6.90	$6.90	$6.37	$6.37	$6.37
2018 to 2022	$6.90	$6.90	$6.37	$6.37	$6.37	$6.90	$6.90	$6.37	$6.37	$6.37
2018 to 2022	$6.90	$6.90	$6.37	$6.37	$6.37	$6.90	$6.90	$6.37	$6.37	$6.37
2023 to 2027	$7.32	$7.32	$6.76	$6.76	$6.76	$7.32	$7.32	$6.76	$6.76	$6.76
2023 to 2027	$7.32	$7.32	$6.76	$6.76	$6.76	$7.32	$7.32	$6.76	$6.76	$6.76
2023 to 2027	$7.32	$7.32	$6.76	$6.76	$6.76	$7.32	$7.32	$6.76	$6.76	$6.76
2023 to 2027	$7.32	$7.32	$6.76	$6.76	$6.76	$7.32	$7.32	$6.76	$6.76	$6.76
2028 to 2032	$7.77	$7.77	$7.18	$7.18	$7.18	$7.77	$7.77	$7.18	$7.18	$7.18
2028 to 2032	$7.77	$7.77	$7.18	$7.18	$7.18	$7.77	$7.77	$7.18	$7.18	$7.18
2028 to 2032	$7.77	$7.77	$7.18	$7.18	$7.18	$7.77	$7.77	$7.18	$7.18	$7.18
2028 to 2032	$7.77	$7.77	$7.18	$7.18	$7.18	$7.77	$7.77	$7.18	$7.18	$7.18

Table 36: High EIA Natural Gas Price Estimates

D – 3: Cooling, Retail Rates ($/kWh)

		50 kW-500 kW	500 kW - 1 MW	1-5 MW	5-20 MW	>20 MW
Alliant	2013	0.1147	0.1115	0.1061	0.1029	0.1029
MN Power	2013	0.1076	0.1074	0.0994	0.0992	0.0962
Xcel Energy	2013	0.0926	0.1184	0.1128	0.1076	0.1042
Otter Tail	2013	0.0830	0.0789	0.0838	0.1015	0.0896
Alliant	2013 to 2017	0.1163	0.1130	0.1076	0.1044	0.1043
MN Power	2013 to 2017	0.1091	0.1089	0.1008	0.1006	0.0975
Xcel Energy	2013 to 2017	0.0940	0.1200	0.1144	0.1091	0.1057
Otter Tail	2013 to 2017	0.0842	0.0800	0.0850	0.1029	0.0909
Alliant	2018 to 2022	0.1205	0.1170	0.1114	0.1081	0.1080
MN Power	2018 to 2022	0.1130	0.1128	0.1044	0.1042	0.1010
Xcel Energy	2018 to 2022	0.0973	0.1243	0.1185	0.1130	0.1094
Otter Tail	2018 to 2022	0.0872	0.0829	0.0880	0.1065	0.0941
Alliant	2023 to 2027	0.1247	0.1212	0.1153	0.1119	0.1119
MN Power	2023 to 2027	0.1170	0.1168	0.1081	0.1079	0.1046
Xcel Energy	2023 to 2027	0.1007	0.1287	0.1227	0.1170	0.1133
Otter Tail	2023 to 2027	0.0903	0.0858	0.0911	0.1103	0.0975
Alliant	2028 to 2032	0.1292	0.1255	0.1194	0.1159	0.1158
MN Power	2028 to 2032	0.1211	0.1210	0.1120	0.1117	0.1083
Xcel Energy	2028 to 2032	0.1043	0.1333	0.1270	0.1211	0.1173
Otter Tail	2028 to 2032	0.0935	0.0889	0.0944	0.1142	0.1009

Table 37: Electric Cooling, Retail Rates

D – 4: Growth Rates

Technical Potential Yearly Growth Rates (%)

Sector	%
Industrial Growth Rate	0.5%
Commercial/Other Growth Rate	1.5%

Table 38: Technical Potential Growth Rates

Energy Price Growth Rates (%)

Fuel	%
Natural Gas	1.2%
Electricity Prices	0.7%

Table 39: Energy Price Growth Rates

STANDBY SERVICE

	OPTION A: FIRM			OPTION B: NON-FIRM		
	On-Peak	**Shoulder**	**Off-Peak**	**On-Peak**	**Shoulder**	**Off-Peak**
Transmission Service	32-941	32-942	32-943	32-950	32-951	32-952
Primary Service	32-944	32-945	32-946	32-953	32-954	32-955
Secondary Service	32-947	32-948	32-949	32-956	32-957	32-958

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RULES AND REGULATIONS: Terms and conditions of this electric rate schedule and the General Rules and Regulations govern use of this service.

AVAILABILITY: This schedule, including Attachment 1 - Definitions and Useful Terms, provides **Backup**, **Scheduled Maintenance**, and **Supplemental Services**, is applicable to any Customer who has the following conditions:

1. Requests to become a **Standby Service Customer** of the Company. Otherwise, the Company views the Customer as a **Non-Standby Service Customer**. For information about the different categories of **Non-Standby Service Customers**, including exemptions from **Standby Service**, please see Attachment No. 1 – Definitions.

2. Utilizes **Extended Parallel Generation Systems** to meet all or a portion of electrical requirements, which is capable of greater than 100 kW. Customers with **Extended Parallel Generation Systems** used to meet all or a portion of electrical requirements that are capable of 100 kW or less are considered **Non-Standby Service Customers** and exempt from paying standby charges. Please see Attachment No. 1-Definitions for more information regarding **Non-Standby Service Customers**.

3. Enters into a contract for services related to its Generator. Contracts will be made for this service provided the Company has sufficient Capacity available in production, transmission and Distribution Facilities to provide such service at the location where the service is requested.

The Company delivers alternating current service at transmission, primary or secondary voltage under this rate schedule, supplied through one Meter.

Power production equipment at the Customer site shall not operate in parallel with the Company's system until the installation has been inspected by an authorized Company representative and final written approval is received from the Company to commence parallel operation.

STANDBY RATE OPTIONS - FIRM AND NON-FIRM

OPTION A: FIRM STANDBY				
	Transmission Service	**Primary Service**	**Secondary Service**	
Firm Standby Fixed Charges				
Customer Charge	$304.33/month	$304.33/month	$242.24/month	**R**
Minimum Monthly Bill	Customer + Reservation + Standby Facilities Charges	Customer + Reservation + Standby Facilities Charges	Customer + Reservation + Standby Facilities Charges	
Summer Reservation Generation Charge per **month** per kW of Contracted Backup Demand	58.422 ¢/kW	62.837 ¢/kW	65.645 ¢/kW	**N** **R**
Winter Reservation Generation Charge per month per kW of Contracted Backup Demand	19.898 ¢/kW	21.403 ¢/kW	22.355 ¢/kW	**N** **R**
Standby Local Distribution Facilities Charge per month per kW of Contracted Backup Demand	Not Applicable	45.00 ¢/kW	55.00 ¢/kW	**N** **R**
Firm Standby On-Peak Demand Charge - Summer				
Metered Demand per **day** per kW On-Peak Backup Charge Transmission & Distribution Substation	48.812 ¢/kW	52.464 ¢/kW	54.794 ¢/kW	**R** **N** **N**
Firm Standby On-Peak Demand Charge - Winter				**R**
Metered Demand per **day** per kW On-Peak Backup Charge Transmission & Distribution Substation	37.420 ¢/kW	40.800 ¢/kW	43.005 ¢/kW	**NNR** **R**
Firm Standby Energy Charges - Summer				**R**
Energy Charges per kWh				
On-Peak Charge	7.840 ¢/kWh	9.367 ¢/kWh	9.672 ¢/kWh	
Shoulder Charge	6.012 ¢/kWh	7.147 ¢/kWh	7.357 ¢/kWh	**R**
Off-Peak Charge	3.429 ¢/kWh	4.047 ¢/kWh	4.146 ¢/kWh	**R**
Firm Standby Energy Charges - Winter				**R**
Energy Charges per kWh				
On-Peak Charge	6.407 ¢/kWh	7.752 ¢/kWh	8.069 ¢/kWh	
Shoulder Charge	5.937 ¢/kWh	7.149 ¢/kWh	7.419 ¢/kWh	
Off-Peak Charge	4.005 ¢/kWh	4.795 ¢/kWh	4.958 ¢/kWh	

OPTION B: NON-FIRM STANDBY	Transmission Service	Primary Service	Secondary Service	
Non-Firm Standby Fixed Charges				
Customer Charge	$304.33/month	$304.33/month	$242.24/month	**R**
Minimum Monthly Bill	Customer + Reservation + Standby Facilities Charges	Customer + Reservation + Standby Facilities Charges	Customer + Reservation + Standby Facilities Charges	
Reservation Generation Charge per month per kW of Contracted Backup Demand	Not Available	Not Available	Not Available	**N**
Standby Local Distribution Facilities Charge per **month** per kW of Contracted Backup Demand	Not Applicable	45.00 ¢/kW	55.00 ¢/kW	**N** **R**
Non-Firm Standby On-Peak Demand Charge - Summer				
Metered Demand per **day** per kW On-Peak Backup Charge Transmission & Distribution Substation	Not Available	Not Available	Not Available	**N** **N**
Non-Firm Standby On-Peak Demand Charge - Winter				
Metered Demand per **day** per kW On-Peak Backup Charge Transmission & Distribution Substation	Not Available	Not Available	Not Available	**N** **N**
Non-Firm Standby Energy Charges - Summer				
Energy Charges per kWh				
On-Peak Charge	Not Available	Not Available	Not Available	**R**
Shoulder Charge	6.012 ¢/kWh	7.147 ¢/kWh	7.357 ¢/kWh	**R**
Off-Peak Charge	3.429 ¢/kWh	4.047 ¢/kWh	4.146 ¢/kWh	
Non-Firm Standby Energy Charges - Winter				
Energy Charges per kWh				
On-Peak Charge	Not Available	Not Available	Not Available	**R**
Shoulder Charge	5.937 ¢/kWh	7.149 ¢/kWh	7.419 ¢/kWh	**R**
Off-Peak Charge	4.005 ¢/kWh	4.795 ¢/kWh	4.958 ¢/kWh	