# APPENDIX A-5

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| A-5-A | Path18 Reservations |
| A-5-B | Standard TPL-002-0 System Performance Following Loss of a Single BES Element |
| A-5-C | Standard TPL 001 thru 004 WECC-1-CR System Performance Criteria |
| A-5-D | NWE: Business Practice OASIS Methodology Criteria and Process FERC Order 9890 Transparency Principle, 05-14-08 |
| A-5-E | NWE: MSTI Phase 1 Comprehensive Progress Report 03/28/08 |
| A-5-F.1 | Rocky Mountain Area Transmission Study (RMATS), 09/2004 |
| A-5-F.2 | RMATS Table of Contents |
| A-5-F.3 | RMATS Executive Summary |
| A-5-F.4 | RMATS Chapter 1 |
| A-5-F.5 | RMATS Chapter 2 |
| A-5-F.6 | RMATS Chapter 3 |
| A-5-F.7 | RMATS Chapter 4 |
| A-5-F.8 | RMATS Chapter 5 |
| A-5-F.9 | RMATS Chapter 6 |

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| A-5-F.10 | RMATS Glossary |
| A-5-G | Base Case Illustrating the Problem 2010 Bath 18 at 387MW without MSTI |
| A-5-H | Example of Immediate Effects of MSTI – 2010 |
| A-5-I | Example Effect of MSTI Five Years Later – 2015 |
| A-5-J | IPC: 2008 Integrated Resource Plan UPDATE, IRPAC DRAFT 05/19/08 |
| A-5-K | Western Electric Coordinating Council (WECC) 2007 Power Supply Assessment 05/19/08 |
| A-5-L | WECC Loads & Resources Data Collection Instruction manual (09/2007) |

# APPENDIX A-5

**ARM 17.20.922 Electric Transmission Lines, Power Transfer Capacity, Voltage Drop**

| Paragraph | Subject Matter | Response |
|---|---|---|
| (1) | *For electric transmission lines where power transfer capacity or voltage drop is a basis of need, the application must contain an explanation of the problem situation including the following information:* | |
| (1)(a) | *where thermal rating is referenced, identification of both the normal and emergency thermal ratings and an explanation of their effect on power flows;* | Not Applicable |
| (1)(b) | *where normal transfer capacity of a transmission line is referenced, identification of a standard power factor and voltage drop limit;* | MSTI will alleviate the congestion that currently exists in the existing Montana to Idaho path, which is called WECC Path 18. Path 18 is fully subscribed in the north to south direction up to its operating limit of 337 MW. See Attachment A-5 A P18 Reservations.<br><br>There is no specific power factor requirement for a transmission line.<br><br>The acceptable voltage drop limit for line outages is defined by NERC and WECC. NERC Table 1, page 4 of Attachment A-5 Attach B TPL-002-02 (note that this same attachment is also |

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| | | attached in the response to K-4) states a "Yes" under the column heading "System Stable and both Thermal and Voltage Limits within Applicable Rating". This means that the system must remain stable and thermal and voltage limits must be within applicable ratings. This column's footnote says that "Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings."<br><br>In order to meet the NERC Applicable Rating requirement, NorthWestern Energy relies on the specific Voltage Dip Standard limit defined in the WECC Table W-1 shown on page 5 of A-5 Attach C TPLstd001-004_4-28-08%20clean (note that this same attachment is also attached in the response to K-4). In the "Transient Voltage Dip Standard" column, the specific WECC criteria is divided into two parts – a limit for the maximum voltage dip after the fault has been cleared and a low voltage time lime (i.e., a limit for how long the voltage can stay below a certain threshold value). Graphical examples of these conditions are provided in Figure W-1 on page 6.<br><br>Maximum Voltage Dip Limit: The maximum voltage dip limit for a single element outage, shown in the Category B row, is not to exceed 25% at load buses or 30% at non-load buses. The maximum voltage dip limit for multiple elements outage, shown in the Category C row, is not to exceed 30% at any bus.<br><br>Low Voltage Time Limit: The limit for how long the voltage can |

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| | | stay below a certain threshold value is the second limit that must be met. A Category B disturbance shall not cause a voltage dip in another system that is greater than 20% for more than 20 cycles at load buses. That is, the voltage cannot be below 0.8 per unit for more than 20 cycles (or 0.333 seconds). For Category C disturbances (i.e., multiple elements outages) the voltage dip in another system is not to exceed 20% for more than 40 cycles at load buses.<br><br>NorthWestern Energy applies these same voltage dip standards for internal outages affecting load busses within the NorthWestern Energy transmission system. |
| (1)(c) | *where emergency power transfer capacity under contingent operating conditions is referenced, identification of the voltage drop and power factor acceptable for the period of contingency;* | Not applicable |
| (1)(d) | *identification of any application design or operating voltage drop standards or legal or contractual voltage drop restrictions;* | In addition to the NERC and WECC performance standards described in (1)(b), NorthWestern Energy has its own voltage and thermal criteria. These criteria start on page 17 in Attachment A-5 Attach D OASIS Method Criteria and Process Business Practice effective 5-14-08 (note that this same attachment is also attached in the response to K-4). Table 2, page 18, provides the minimum allowable percentage voltage at NorthWestern Energy's unregulated load-service bus. For example, after an outage the voltage must recover (post fault) to 97%, which is a voltage drop of 3%. |
| (1)(e) | *a minimum of three load flow studies. The* | |

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| | *load flow studies must clearly indicate any assumptions made, including any relevant input data, and must include a single line diagram showing megawatts and megvar loads and flows and voltage levels for each study. The studies must include the following unless otherwise approved by the department:* | |
| (1)(e)(i) | *the base case, illustrating the problem;* | The base case that will be used to illustrate the problem is derived by removing MSTI from the 2010 Light Autumn base case used in the MSTI's Phase 1 Comprehensive Progress report (A-5 Attach E MSTI_CPR_FINAL). The Phase 1 study is the first of two technical studies that must be completed to obtain a WECC Approved Path Rating. The process that must be followed is defined within the WECC Procedure for Project Rating Review (see K-4 Attach D).<br><br>The Problem<br><br>The problem that exists is that there is insufficient transmission transfer capability out of Montana to accommodate the Transmission Service Requests that NorthWestern Energy received through its Montana to Idaho open season. In addition, there is insufficient transmission to move additional MW associated with new generation development in Montana.<br><br>Currently, NorthWestern Energy is an exporting control area. The total amount of existing generation in Montana substantially exceeds the existing load. Thus every MW of new generation that is developed increases transmission exports. The existing path between Montana and Idaho, Path 18, is congested above its stated north to south operating limit of 337 MW. A graphical representation of the congestion appears in |

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| | | Chapter 2, page 2-11, of the Rocky Mountain Area Transmission Study. See Attachment A-5 Attach F.5 RMATS Chapter 2.<br><br>The 337 MW operating limit is established as the maximum MW flow that can be moved without violating post fault recovery voltage criteria at Dillon, MT and Peterson Flats, ID. Dillon is on the 161 kV line and Peterson Flats is on the 230 kV. These two lines are Path 18. At 337 MW the WECC post fault voltage recovery performance requirements are met after the critical double line outage, which is the loss of two of the three 345 kV lines (i.e., Bridger to Kinport and Bridger to Goshen) that are westward bound from the Jim Bridger generating complex.<br><br><u>Base Case Illustrating the Problem</u><br><br>At 337 MW flow, Path 18 meets the criteria for the critical double line outage. Above this flow the criteria is not met. This problem is demonstrated by examining the results graphically in a one-line diagram provided in A-5 Attach G Base Case Illustrating Problem P18 387 Problem. In this one-line diagram, Path 18 is shown on the lower half of the right side of the diagram. Increasing the Path 18 flows by 50 MW (which is less the current Transmission Service Requests of 639 MW and substantially less than the 1,500 MW path rating NorthWestern Energy is seeking for MSTI) to 387 MW unacceptable voltage drops occurs on both lines after the loss of the to 345 kV lines described above. This single line diagrams also show megawatts and megvar loads and flows and voltage levels required by this question.<br><br><u>Relevant Input Data</u><br><br>On page 9 of the MSTI's Phase 1 Comprehensive Progress Report (A-5 Attach E MSTI_CPR_FINAL) a narrative of the Base |

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| | | Case Description and Expected Operating Conditions for this base case are provided. In addition, a detailed table of the relevant load, line flows and generation dispatch are provided in a table on pages 12–15. An examination of the 2010 light autumn (2010 LA) without Fast Track Projects column will yield the relevant input data. |
| (1)(e)(ii) | *a study showing the immediate effect of the facility; and* | The base case that will be used to demonstrate the immediate affect of MSTI is the 2010 light autumn base case from MSTI's Phase 1 Comprehensive Progress report (A-5 Attach E MSTI_CPR_FINAL). This study is the first of two technical studies that must be completed to obtain a WECC Approved Path Rating. The process that must be followed is defined within the WECC Procedure for Project Rating Review (see K-4 Attach D).<br><br><u>Immediate Effect of MSTI</u><br><br>The immediate effect of adding MSTI is that the transfer capability out of Montana is increased by up to 1500 MW depending on load and resource dispatch conditions. This effect can be found in the conclusions section, page 11, of Comprehensive Progress Report, A-5 Attach E. It states that "[t]his study shows that the MSTI performance is acceptable at the proposed path rating of 1500 MW North to South and 950 MW South to North for the non-simultaneous conditions studied." In addition, under the Power Flow Results it states that "[i]n the light autumn cases, 1500 MW was reached with the addition of the NTTG Fast Track projects and a limit of approximately 1400 MW without the NTTG Fast Track projects. This limit of 1400 MW was because of a limitation of angle on the phase shifting transformer."<br><br><u>Base Case Illustrating the Immediate Effect of MSTI</u> |

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| | | The 2010 light autumn base case that demonstrates the immediate effect of MSTI is shown graphically in a one-line diagram in Attachments A-5 Attach H Immediate Effects of MSTI. In this one-line diagram, MSTI has been added between Montana to Idaho. MSTI is shown in the left hand side of the diagram and Path 18 on the lower right hand side. In this base case MSTI is flowing 1324 MW north to south and no low voltage appear. The higher voltage levels shown would require voltage control devices to be installed, which would be part of the facility design.<br><br><u>Relevant Input Data</u><br><br>On page 9 of the Comprehensive Progress Report (A-5 Attach E MSTI_CPR_FINAL) a narrative of the Base Case Description and Expected Operating Conditions are provided. In addition, a detailed table of the relevant load, line flows and generation dispatch are provided in a table on pages 12–15. An examination of the 2010 light autumn (2010 LA) without Fast Track Projects column will yield the relevant input data. |
| (1)(e)(iii) | *a study showing the effect of the facility five years later.* | The base case that will be used to demonstrate the effect of MSTI five years later is the 2015 heavy summer base case from MSTI's Phase 1 Comprehensive Progress report (A-5 Attach E MSTI_CPR_FINAL). This study is the first of two technical studies that must be completed to obtain a WECC Approved Path Rating. The process that must be followed is defined within the WECC Procedure for Project Rating Review (see K-4 Attach D).<br><br><u>Effect of MSTI Five Years Later</u><br><br>The effect of MSTI on the transmission system five years later can be found in MSTI's Phase 1 report for the WECC Procedure for Project Rating Review. In the Phase 1 study, NorthWestern |

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| | | Energy used two base cases - a 2010 light autumn base case and a 2015 heavy summer base case.<br><br>The conclusion from the 2015 light autumn Phase 1 power flow study results (see page 11 of A-5 Attach E MSTI_CPR_FINAL) is that "[i]n both heavy summer cases, 1500 MW was achieved."<br><br><u>Base Case Illustrating the Effect of MSTI Five Years Later</u><br><br>The 2015 heavy summer base case that demonstrates the effect of MSTI five years later is shown graphically in a one-line diagram in Attachments A-5 Attach I Effect of MSTI Five Years Later. In this one-line diagram, MSTI has been added between Montana and Idaho and the year is 2015 (five years later from the illustration in response to (1)(e)(ii)). MSTI is shown in the left hand side of the diagram and Path 18 on the lower right hand side. In this base case MSTI is flowing 1493 MW north to south. All low voltage levels meet criteria.<br><br><u>Relevant Input Data</u><br><br>On page 9 of the Comprehensive Progress Report (A-5 Attach E MSTI_CPR_FINAL) a narrative of the Base Case Description and Expected Operating Conditions are provided. In addition, a detailed table of the relevant load, line flows and generation dispatch are provided in a table on pages 12–15. An examination of the 2015 heavy summer (2015 HS) without Fast Track Projects column will yield the relevant input data. |
| (1)(f) | *ten-year historical and 10-year projected load growth at each point of distribution in the area that would be served by the facility, including the following:* | NorthWestern Energy cannot provide the forecast at each point of distribution in the area that MSTI Transmission Service Requests may ultimately serve because these customers could be located anywhere in the western United States. NorthWestern Energy's Transmission Service Requests will be |

Idaho. From the Midpoint substation to the point-of-receipt Transmission Service Request(s) on all Transmission Providers transmission systems must be obtained. Until these Transmission Service Requests have been made, the exact point-of-delivery is not known, therefore the ten-year historical and 10-year projected load growth at each point of distribution in the area that would be served by the facility cannot be provided.

However, an area peak forecast for the areas that MSTI Transmission Service Requests might serve can be provided. In Idaho the historical and forecast for Idaho's aggregated peak load is provided in Attachment A-5 Attach J IPC draft2008IPRupdate. Idaho's median load growth is 1.8% and is shown in Table 4 page 19 of Idaho Power's 2008 Integrated Resource Plan Update. A historical peak load table is not provided in the report.

If the MSTI Transmission Service Requests extends beyond Idaho Power, a forecast of customer load growth is described in the 2007 WECC Power Supply Assessment. No historical data is provided. The various sub-regions 2008-2016 WECC load forecasts that utilities provided to WECC in 2007 are shown in the table below.

| WECC Sub Region Firm Demand, MW | | | |
|---|---|---|---|
| | 2008 | 2016 | Growth |
| Canada | 17,568 | 20,422 | 1.9% |
| Northwest | 23,922 | 26,487 | 1.3% |
| Basin | 11,850 | 14,370 | 2.4% |
| Rockies | 12,635 | 15,286 | 2.4% |
| Desert SW | 30,573 | 37,978 | 2.7% |
| No. CA | 26,148 | 29,970 | 1.7% |

| | | |
|---|---|---|
| | | <table><tr><td>So CA/MX</td><td>33,899</td><td>38,762</td><td>1.7%</td></tr><tr><td>WECC</td><td>156,595</td><td>183,275</td><td>2.0%</td></tr><tr><td colspan="4">From WECC 2007 Power Supply Assessment, Table 18, page 60.</td></tr></table><br>The utilities that make up each sub-region's forecast are shown in Table 4, page 9 of the 2007 Power Supply Assessment report (see Attachment A-5 Attach K WECC PSA_Final_Report_09-17-07). |
| (1)(f)(i) | *a description of the assumptions used in making the projection, and an evaluation of the extent to which load growth in the area to be served by the facility will follow or differ for the patterns shown in overall service area load growth of the applicant;* | The information that explains the Idaho Power forecast assumptions is found in Chapter 3 Planning Period Forecast, pages 15-19 of their 2008 Integrated Resource Plan Update (see A-5 Attach J IPC draft2008IPRupdate).<br><br>The information that NorthWestern Energy has to explain the WECC forecasts is provided within the instruction that WECC provided to utilities for submitting their load forecast data. See Attachment A-5 Attach L WECC Instructions, pages 32-33 for information regarding the WECC load forecast instructions. |
| (1)(f)(ii) | *if additional block loads equal to 10% or more of a given substation load are anticipated, a list of the total connected load and the after-diversity-maximum demand for each additional load;* | Not Applicable |
| (1)(f)(iii) | *for substations which are delivery points for resale customers, the applicant may substitute the resale customer's forecast of load growth at that delivery point for the applicant's own forecast. In such cases an evaluation of the resale customer's forecasting method must be* | Not Applicable |

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| | *included; and* | |
| (1)(f)(iv) | *an explanation of the amount of excess capacity which will be available after the proposed transmission line is built, under contingent and normal conditions, and an estimate of when additional reinforcement will be necessary.* | The excess capacity above the firm Transmission Service Requests after MSTI is built is not precisely known at this time – it will depend on the amount of transmission Service Requests that are ultimately received. It is NorthWestern Energy's goal to fully subscribe MSTI. Currently, NorthWestern Energy has Transmission Service Requests for 639 MW. |

## APPENDIX A-5-A

### Path 18 Firm Reservations
### June 2008

| | Service | Status | MW Grant | Point Of Delivery |
|---|---|---|---|---|
| NWE | YEARLY FIRM | CONFIRMED | 4 | BORAH/BRADY |
| NWE | YEARLY FIRM SL | CONFIRMED | 1 | BORAH/BRADY |
| NWE | YEARLY FIRM | CONFIRMED | 30 | BORAH/BRADY |
| NWE | YEARLY FIRM SL | CONFIRMED | 30 | BORAH/BRADY |
| NWE | YEARLY FIRM SL | CONFIRMED | 15 | BORAH/BRADY |
| NWE | TOTAL | | 80 | BORAH/BRADY |
| PAC * | TOTAL | | 90 | BORAH/BRADY |
| IPC * | TOTAL | | 80 | BORAH/BRADY |
| AMPS LINE | TOTAL | | 250 | BORAH/BRADY |

| | Service | Status | MW Grant | Point Of Delivery |
|---|---|---|---|---|
| | YEARLY FIRM | CONFIRMED | 7 | JEFFERSON |
| | YEARLY FIRM | CONFIRMED | 66 | JEFFERSON |
| | YEARLY FIRM | CONFIRMED | 7 | JEFFERSON |
| | YEARLY FIRM SL | CONFIRMED | 7 | JEFFERSON |
| | | | 87 | |
| PATH 18 | TOTAL | | 337 | |

* Amount of capacity each has contract rights.

# APPENDIX A-5-A

# APPENDIX A-5-B

## Standard TPL-002-0 — System Performance Following Loss of a Single BES Element

### A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-0

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   **4.1.** Planning Authority

   **4.2.** Transmission Planner

5. **Effective Date:** April 1, 2005

### B. Requirements

**R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

**R1.1.** Be made annually.

**R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

**R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories,, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

**R1.3.1.** Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

**R1.3.2.** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

**R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.

**R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

**R1.3.5.** Have all projected firm transfers modeled.

**R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system Demands.

**R1.3.7.** Demonstrate that system performance meets Category B contingencies.

**R1.3.8.** Include existing and planned facilities.

**R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

**R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.

**R1.3.11.** Include the effects of existing and planned control devices.

**R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

**R1.4.** Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

**R1.5.** Consider all contingencies applicable to Category B.

**R2.** When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

**R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

**R2.1.1.** Including a schedule for implementation.

**R2.1.2.** Including a discussion of expected required in-service dates of facilities.

**R2.1.3.** Consider lead times necessary to implement plans.

**R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

**R3.** The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

## C. Measures

**M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

**M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

**Compliance Monitor:** Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

#### 1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

#### 1.3. Data Retention

None specified.

#### 1.4. Additional Compliance Information

None.

### 2. Levels of Non-Compliance

**2.1. Level 1:** Not applicable.

**2.2. Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

## E. Regional Differences

1. None identified.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 0 | April 1, 2005 | Effective Date | New |
| | | | |
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| | | | |

### Table I. Transmission System Standards — Normal and Emergency Conditions

| Category | Contingencies | System Limits or Impacts | | |
|---|---|---|---|---|
| | Initiating Event(s) and Contingency Element(s) | System Stable and both Thermal and Voltage Limits within Applicable Rating[a] | Loss of Demand or Curtailed Firm Transfers | Cascading Outages |
| **A**<br>No Contingencies | All Facilities in Service | Yes | No | No |
| **B**<br>Event resulting in the loss of a single element. | Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>Loss of an Element without a Fault. | Yes<br>Yes<br>Yes<br>Yes | No[b]<br>No[b]<br>No[b]<br>No[b] | No<br>No<br>No<br>No |
| | Single Pole Block, Normal Clearing[e]:<br>4. Single Pole (dc) Line | Yes | No[b] | No |
| **C**<br>Event(s) resulting in the loss of two or more (multiple) elements. | SLG Fault, with Normal Clearing[e]:<br>1. Bus Section<br>2. Breaker (failure or internal Fault) | Yes<br>Yes | Planned/ Controlled[c]<br>Planned/ Controlled[c] | No<br>No |
| | SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]:<br>3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency | Yes | Planned/ Controlled[c] | No |
| | Bipolar Block, with Normal Clearing[e]:<br>4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]:<br>5. Any two circuits of a multiple circuit towerline[f] | Yes<br>Yes | Planned/ Controlled[c]<br>Planned/ Controlled[c] | No<br>No |
| | SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure):<br>6. Generator<br>7. Transformer<br>8. Transmission Circuit<br>9. Bus Section | Yes<br>Yes<br>Yes<br>Yes | Planned/ Controlled[c]<br>Planned/ Controlled[c]<br>Planned/ Controlled[c]<br>Planned/ Controlled[c] | No<br>No<br>No<br>No |

| | | |
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| D [d]<br><br>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service | 3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure):<br>1. Generator<br>2. Transmission Circuit<br>3. Transformer<br>4. Bus Section<br>3Ø Fault, with Normal Clearing [e]:<br>5. Breaker (failure or internal Fault)<br>6. Loss of towerline with three or more circuits<br>7. All transmission lines on a common right-of way<br>8. Loss of a substation (one voltage level plus transformers)<br>9. Loss of a switching station (one voltage level plus transformers)<br>10. Loss of all generating units at a station<br>11. Loss of a large Load or major Load center<br>12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required<br>13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate<br>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization. | Evaluate for risks and consequences.<br>▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.<br>▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point.<br>▪ Evaluation of these events may require joint studies with neighboring systems. |

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

# APPENDIX A-5-B

**Definitions**

**Common Corridor:**

Contiguous right-of-way or two parallel right-of-ways with structure centerline separation less than the longest span length of the two transmission circuits at the point of separation or 500 feet, whichever is greater, between the transmission circuits. This separation requirement does not apply to the last five spans of the transmission circuits entering into a substation.

**Adjacent Transmission Circuits:**

Transmission circuits within a Common Corridor with no other transmission circuits between them. Transmission Lines that cross but are otherwise on separate corridors are not Adjacent Transmission Circuits.

## A. Introduction

1. **Title: System Performance Criteria Under Normal Conditions, Following Loss of a Single BES Element, and Following Extreme BES Events**

2. **Numbers:** TPL-001-WECC-1-CR

   TPL-002-WECC-1-CR

   TPL-003-WECC-1-CR

   TPL-004-WECC-1-CR

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability**

   **4.1.** Planning Authority

   **4.2.** Transmission Planner

5. **Effective Date:** April 18, 2008

## B. Requirements

**WRS1.** In addition to NERC Table I, Planning Authorities or Transmission Planners shall comply with the WECC Disturbance-Performance Table (Table W-1) of Allowable Effects on Other Systems contained in this section when planning the Western Interconnection. Table W-1 does not apply internal to a Transmission Operator Area.

**WRS1.1.** The NERC Category C.5 initiating event of a non-three phase fault with normal clearing shall also apply to the common mode contingency of two Adjacent Transmission Circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

**WRS1.2.** The common mode simultaneous outage of two generator units connected to the same switchyard, not addressed by the initiating events in NERC Category C, shall not result in cascading.

**WRS1.3.** The loss of multiple bus sections as a result of a failure or delayed clearing of a bus tie or bus sectionalizing breaker shall meet the performance specified for Category D of Table W-1.

**WRS1.4.** For contingencies involving existing or planned facilities, the Table W-1 performance category can be adjusted based on actual or expected performance (e.g. event outage frequency and consideration of impact) after receiving Board approval to change the Performance Level Adjustment Record.

**WRS2.** Individual systems or a group of systems may apply requirements that differ from specific requirements in Table W-1 for internal impacts. If the individual requirements are less stringent, other systems are permitted to have the same impact on that part of the individual system for the same category of disturbance. If these requirements are more stringent, these requirements may not be imposed on other systems. This does not relieve the system or group of systems from WECC requirements for impacts on other systems.

**WRS3.** Reactive power resources, with a balance between static and dynamic characteristics, shall be planned and distributed throughout the interconnected transmission systems to ensure system performance as defined below.

**WRS3.1.** For transfer paths, voltage stability is required with the pre-contingency path flow modeled at a minimum of 105% of the path rating for system normal conditions (Category A) and for single contingencies (Category B). For multiple contingencies (Category C), post-transient voltage stability is required with the pre-contingency transfer path flow modeled at a minimum of 102.5% of the path rating.

**WRS3.2.** For load areas, voltage stability is required for the area modeled at a minimum of 105% of the reference load level for system normal conditions (Category A) and for single contingencies (Category B). For multiple contingencies (Category C), post-transient voltage stability is required with the area modeled at a minimum of 102.5% of the reference load level. For this criterion, the reference load level is the maximum established planned load limit for the area under study.

**WRS3.3.** Specific requirements that exceed the minimums specified in WRS3.1 and WRS3.2 may be established, to be adhered to by others, provided that technical justification has been approved by the Planning Coordination Committee (PCC) of the WECC.

**WRS3.4.** WRS3 applies to internal WECC Member Systems as well as between Member Systems.

**WRS4.** The Planning Authorities and Transmission Planners shall meet the same performance category for unsuccessful reclosing as that required for the initiating disturbance without reclosing.

**WRS5.** For any event that has actually resulted in cascading, action must be taken so that future occurrences of the event will not result in cascading, or it must demonstrate that the Mean Time Between Failure (MTBF) is greater than 300 years (frequency less than 0.0033 outages/year) and approved by PCC.

**WR5.1.** Any contingency adjusted to Category D must not result in a cascading outage unless the MTBF is greater than 300 years (frequency less than 0.0033 outages/year) or the initiating disturbances and corresponding impacts are confined to either a radial system or a local network.

## C. Measures

**WMS1.** Planning Authority or Transmission Planner has documentation that it complies with the WECC Disturbance-Performance Table (Table W-1) of Allowable Effects on Other Systems as required by WRS1.

**WMS2.** The Planning Authority or Transmission Planner has documentation that it has planned for reactive power resource as required by WRS3.

**WMS3.** The Planning Authority or Transmission Planner has documentation that it meets the same performance category for unsuccessful reclosing as required by WRS4.

**WMS4.** The Planning Authority or Transmission Planner with less stringent individual requirements than these WECC requirements has documentation that other Planning

Authorities or Transmission Planners performance are permitted to have the same impact on that part of the individual system for the same category of disturbance.

**WMS5.** The Planning Authority or Transmission Planner has documentation that it has Planning Coordination Committee (PCC) approval to adjust in Table W-1 the Performance Level Adjustment Record involving existing or planned facilities.

**WMS6.** For any event that has actually resulted in cascading, the Planning Authority or Transmission Planner shall have documentation that it has taken action so that future occurrences of the event will not result in cascading, or it must have documentation that it has PCC approval that the Mean Time Between Failure (MTBF) is greater than 300 years (frequency less than 0.0033 outages/year).

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Monitoring Responsibility

Western Electricity Coordinating Council (WECC)

#### 1.2. Compliance Monitoring Period and Reset

Annual

#### 1.3. Data Retention

Four Years

#### 1.4. Additional Compliance Information

None

**Version History** – Shows Approval History and Summary of Changes in the Action Field

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 1 | April 18, 2008 | Replaces the Part I - NERC/WECC Planning Standards | |

## WECC DISTURBANCE-PERFORMANCE TABLE OF ALLOWABLE EFFECTS ON OTHER SYSTEMS

| NERC and WECC Categories | Outage Frequency Associated with the Performance Category (outage/year) | Transient Voltage Dip Standard | Minimum Transient Frequency Standard | Post Transient Voltage Deviation Standard (See Note 3) |
|---|---|---|---|---|
| A | Not Applicable | Nothing in addition to NERC | | |
| B | ≥ 0.33 | Not to exceed **25%** at load buses or **30%** at non-load buses.<br><br>Not to exceed **20% for more than 20 cycles** at load buses. | Not below **59.6** Hz for 6 cycles or more at a load bus. | Not to exceed **5%** at any bus. |
| C | 0.033 – 0.33 | Not to exceed **30%** at any bus.<br><br>Not to exceed **20% for more than 40 cycles** at load buses. | Not below **59.0** Hz for 6 cycles or more at a load bus. | Not to exceed **10%** at any bus. |
| D | < 0.033 | Nothing in addition to NERC | | |

***Notes:***

1. *The WECC Disturbance-Performance Table applies equally to either a system with all elements in service, or a system with one element removed and the system adjusted.*

2. *As an example in applying the WECC Disturbance-Performance Table, a Category B disturbance in one system shall not cause a transient voltage dip in another system that is greater than 20% for more than 20 cycles at load buses, or exceed 25% at load buses or 30% at non-load buses at any time other than during the fault.*

*Table W-1*

3. *If it can be demonstrated that post transient voltage deviations that are less than the values in the table will result in voltage instability, the system in which the disturbance originated and the affected system(s) shall cooperate in mutually resolving the problem.*

4. *Refer to Figure W-1 for voltage performance parameters.*

5. *Load buses include generating unit auxiliary loads.*

6. *To reach the frequency categories shown in the WECC Disturbance-Performance Table for Category C disturbances, some planned and controlled islanding may occur. Underfrequency load shedding is expected to arrest this frequency decline and assure continued operation within the resulting islands.*

7. *For simulation test cases, the interconnected transmission system steady state loading conditions prior to a disturbance shall be appropriate to the case. Disturbances shall be simulated at locations on the system that result in maximum stress on other systems. Relay action, fault clearing time, and reclosing practice shall be represented in simulations according to the planning and operation of the actual or planned systems. When simulating post transient conditions, actions are limited to automatic devices and no manual action is to be assumed.*

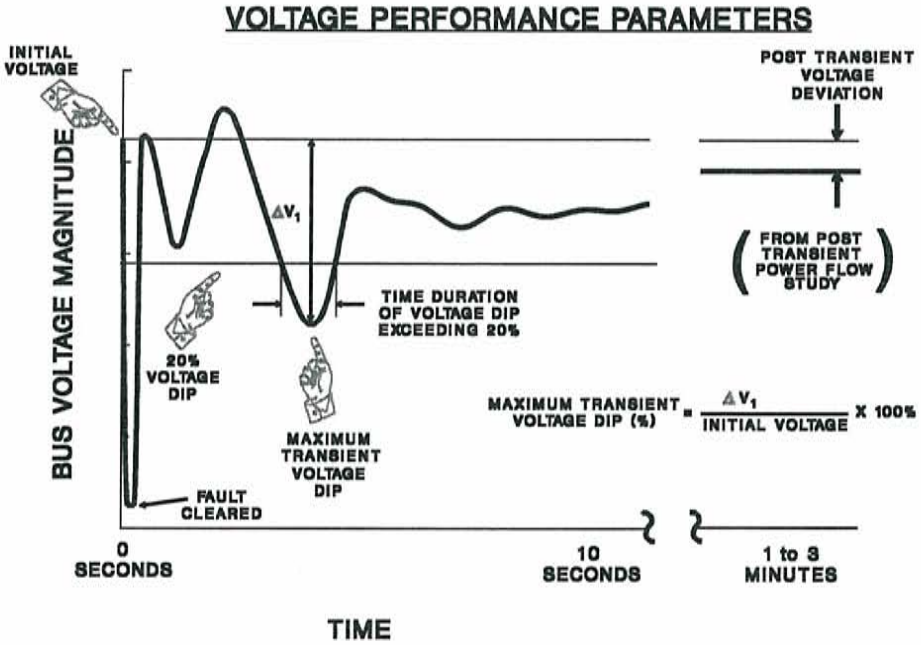


*Figure W-1*

NorthWestern™ Energy

# Business Practice

# OASIS Methodology, Criteria and Process

## FERC Order 890
## Transparency Principle

Effective Date
From: May 14, 2008
To: _____

# APPENDIX A-5-D

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# APPENDIX A-5-D

# Introduction

NorthWestern Energy ("NWE") methodology, process and criteria described herein are used to evaluate the transmission system, ensuring that system reliability is maintained into the future. Reliability, by definition, examines the adequacy and security of the electric transmission system. One of NWE's transmission planning goals is to identify the best solution to resolve a transmission reliability concern.

FERC Order 890 Principle 3, Transparency, includes the following requirement.

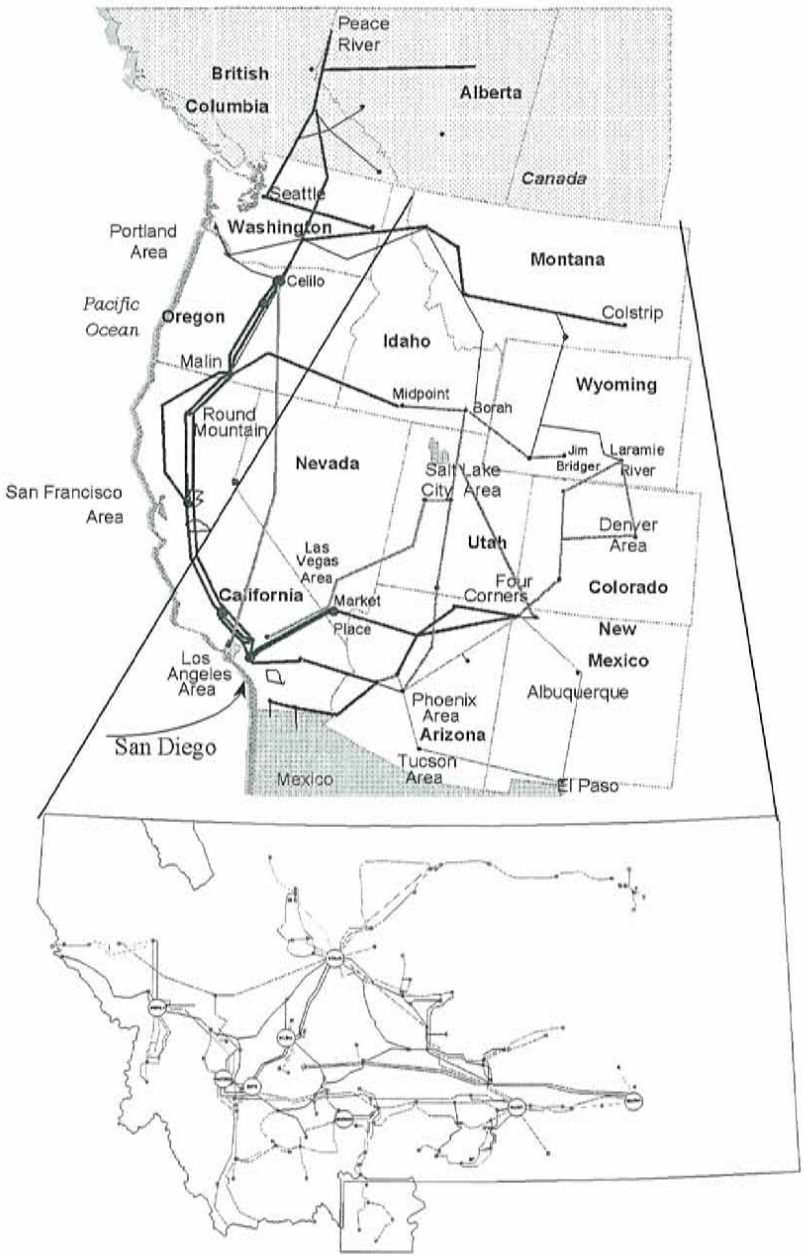
> "In addition, transmission providers will be required to reduce to writing and make available the basic methodology, criteria, and processes they use to develop their transmission plan, including how they treat retail native loads, in order to ensure that standards are consistently applied." Paragraph 471

The above requirement calls for information as to "how they treat retail native loads, in order to ensure that standards are consistently applied." Consistent application of the methodology, criteria, and process for all balancing area customers (i.e., retail, network and point-to-point) information is ensured through the openness and transparency of NWE's process. All customers are treated on an equal and comparable basis using the transmission system planning process, methodology and criteria described herein. All customer data are included in the planning analysis without regard to their classification. NWE's transmission system planning process is designed to be transparent, open and understandable. The information described herein reflects existing practice, with the addition of new processes that encompass Order 890 transmission system planning requirements. For example, NWE planning process is being expanded to include input from stakeholders and other interested parties during the planning stage.

FERC Order 890 makes a distinction between the transmission system planning for load due to customers' needs (i.e., system planning) and planning for new generation interconnection. NWE adheres to the FERC Large Generation Interconnection Procedures ("LGIP") and Small Generation Interconnection Procedures ("SGIP") requirements to study generation interconnection. In studying a request for transmission service, NWE follows its tariff requirements as provided on NWE's OASIS Website (see http://www.oatioasis.com/NWMT/). This process is also described in NWE's Transmission Service Study Procedures Manual that is posted on NWE's OASIS Website. NWE's study methods requirements for large new transmission-connected load can also be found on NWE's OASIS Website.

# NWE Local Transmission System

NWE local transmission system provides regulated electric transmission services to approximately 300,000 electric customers. NWE's electric transmission system consists of approximately 7,000 miles of transmission lines and associated terminal facilities. NWE is registered as a Balancing Authority, Planning Authority and Transmission Planner. NWE does not currently own generation.

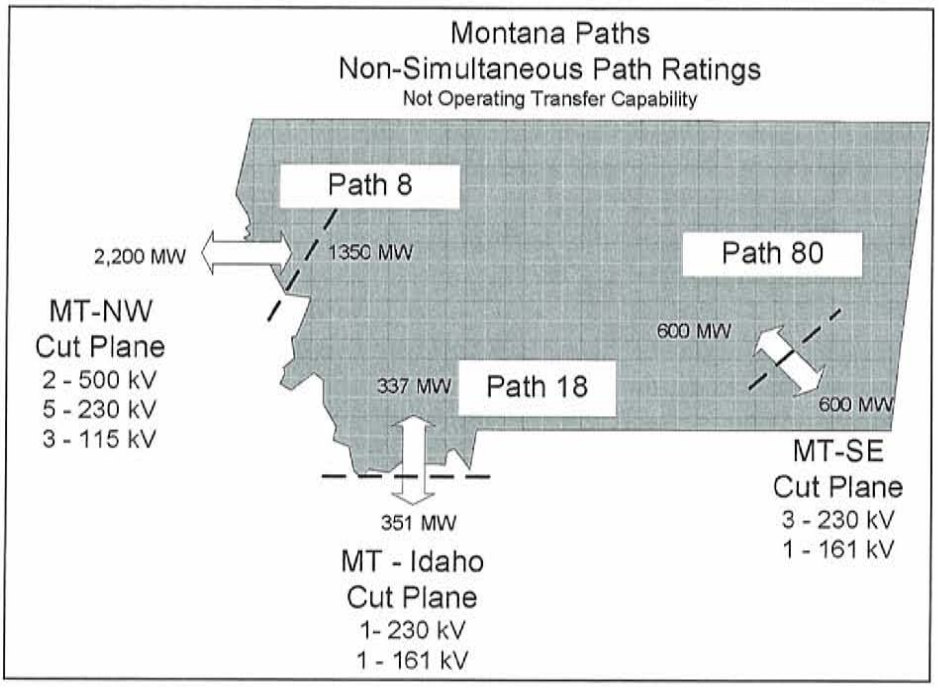



The transmission system, with voltage levels ranging from 50,000 to 500,000 volts, serves an area of 97,540 square miles, which is equivalent to two-thirds of Montana. The 500 kV transmission system is primarily used to move power from Colstrip in eastern Montana to the Northwest. NWE's transmission system has interconnections to five major transmission systems[1] located in the Western Electricity Coordinating Council ("WECC") area and one DC interconnection to a system that connects with the Mid-Continent Area Power Pool ("MAPP") region.

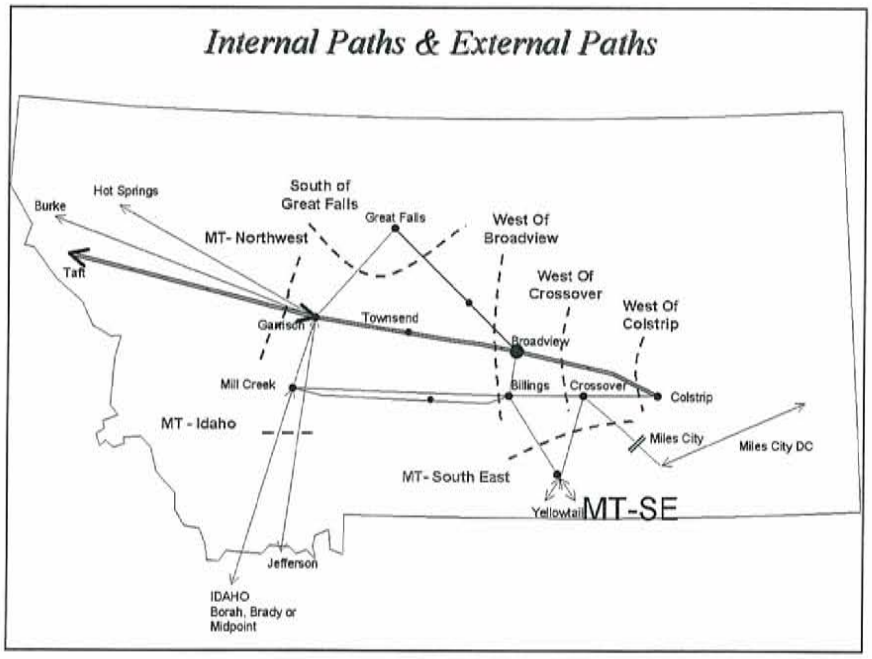
[1] Idaho Power Company, Avista Corporation, Bonneville Power Administration, Western Area Power Administration and PacifiCorp.

## APPENDIX A-5-D

The following graphic displays the external paths and associated non-simultaneous path ratings.



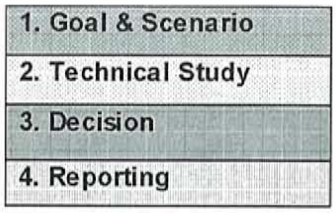

The graphic below also displays NWE's internal paths.



Basic Methodology
Below is a discussion of NWE's basic methodology that is used to formally analyze its local transmission system. By application of this methodology, NWE ensures that a reliable transmission system exists to serve network customer load and firm point-to-point transmission service requests. NWE's methodology is intended to define operating conditions that fail to meet reliability criteria and then identify solutions (e.g., transmission and non-transmission[2]) that solve the problem. The operating conditions are for a specific instant in time, such as peak load conditions, and are not an integrated time period, such as an hour, day, month, etc. NWE's basic methodology described below is focused on transmission reliability and not economic congestion studies that can be requested by customers.

NWE's goal is to design a reliable, least cost transmission system that will perform under expected operating conditions wherein customer load can be met reliably into the future. NWE's methodology includes transmission system planning and the WECC Annual Study Plan.

## *NWE Transmission System Planning Methodology*




NWE's methodology includes the four steps shown in the graph to the right. These steps are (1) Goal and Scenario Definition, (2) Technical Study, (3) Decision, and (4) Reporting. How these steps are weaved together to formulate the transmission plan is described in the Process section of this document. Transmission system planning may be confined to a specific geographic area, such as the Bozeman area, or it may be broadened to examine a specific transmission line or lines that extend over a large geographic area, such as NWE's Montana balancing area. The transmission lines used in a system planning study may range in size from 50 kV to 500 kV and may be networked or radial.

Electric transmission system planning methodology involves forecasting customer demand, identifying area reliability problems, evaluating possible mitigation options and selecting a solution that solves the area's transmission needs. Transmission system planning evaluates the transmission system reliability up to 15 years in the future. The planning effort considers transmission and non-transmission alternatives to resolve the reliability problem for a specified area. NWE's methodology is flexible and is intended to develop a plan that:

- Responds to customers needs;
- Is low cost (e.g., Total Present Value Revenue Requirement, Rate Impact, etc.);
- Considers non-transmission and transmission alternatives;
- Assesses future uncertainty and risk;
- Promotes NWE's commitment to protecting the environment;
- Includes input from the public and other interested parties;

[2] Demand-side resource, generation, interruptible load, etc.

- Provides adequate return to investors;
- Complements corporate goals and commitments;
- Meets FERC Standards and WECC Standards;
- Meets the Montana Public Service Commission expectations;
- Meets Regional and Sub-Regional planning requirements;
- Satisfies the requirements of the FERC Order 890; and
- Conforms to applicable state and national laws and regulations.

## Goal and Scenario Definition

NWE uses scenario planning and not probabilistic planning for developing the electric transmission system plan. NWE may, however, use probabilistic assessment methods within a defined scenario to evaluate uncertainty. The design of the scenario is to "crystal ball" the future in order to identify conditions that stress the transmission system.

NWE will work with its Transmission Advisory Committee[3] ("TRANSAC") to establish the goal of the transmission plan. The scenarios will be developed using this goal as a basis. A scenario will depict a specific condition such as summer peak load with maximum generation and exports out of the state. NWE's transmission system is exporting power most of the time since Montana has significantly more generation than load. It is important to note that a scenario should be designed to stress the transmission system under conditions that may cause inadequate transmission system performance to meet reliability criteria. Experience has shown that the transmission system is stressed when flows across it are heavy. However, experience has also shown that the transmission system may display problems under conditions that are less than maximum flows due to the way electrical equipment engages operation or ceases operation. Once a problem is found, solutions that mitigate the problem are defined and evaluated.

NWE's basic methodology is to define the base scenarios to study and then to develop uncertainty scenarios from these base scenarios. This methodology is described in more detail below.

### *Base Scenarios*

Base case scenarios will be used to examine the transmission system under a variety of future assumptions for a specific period of time. These assumptions include, but are not limited to, the following:

- Load Forecast (e.g., study year)
- Load Condition to Study (e.g. season, peak load or light load, etc.)
- Generation Available (e.g., generation additions/changes)
- Generation Dispatch Conditions (e.g., how is the generation operated)

[3] TRANSAC is an advisory stakeholder committee that meets regularly with NWE to provided input and comments during the planning stages of NWE's electric transmission system plan. Membership is open and communication is open and transparent. For more information visit NWE's Transmission Planning section on NWE's OASIS Website (http:/www.oatioasis.com/NWMT/).

- Transmission System Elements Available (e.g., transmission element additions/changes)
- Transmission System Configuration (e.g., what elements are out-of-service)

Even though new interconnect projects follow FERC's defined interconnection methods, the study results from the new interconnect projects cannot be ignored in transmission system planning. The addition of new generation to NWE's transmission system can affect the flows throughout the system. Additional power flows from the new generation, and flow changes due to transmission system upgrades, if upgrades are required. NWE, with input from its TRANSAC, will consider scenarios including new generators with associated transmission or develop uncertainty scenarios that include this information.

*Uncertainty Scenarios*

The uncertainty scenarios are intended to recognize that the future, as assumed in the base scenarios, is not known. This uncertain future creates risk, which may be quantifiable or non-quantifiable. Risk may be expressed as a dollar cost or other impact. The base scenarios must make assumptions about future conditions, but the uncertainty scenario helps with understanding the risk associated with those assumptions. The purpose of the uncertainty scenarios is to develop information about the cost and electrical performance of base scenarios so that an informed decision about future transmission investments can be made.

## Technical Study

The technical study is the second step in electric transmission system planning. It examines the reliability of NWE's electric transmission lines that move power around NWE's balancing area and between the bulk electric transmission system and the distribution system. NWE uses a sophisticated computer model (i.e., PSS/E) to simulate generator output, electrical flows over the transmission lines, electrical equipment action, customer loads and export (or import) path flows. The purpose of the technical study is to quantify transmission system performance by measuring the bus voltage, equipment loading, reactive power requirement, system frequency and other electrical parameters.

NWE does not conduct studies for every possible load and resource dispatch combination for the 8760 hours of the year. Instead, only the load and resource dispatch patterns that stress the transmission system are evaluated. The conditions that stress the transmission system are used in a computer simulation of the electrical system. The reliability[4] of the local transmission system is evaluated with all transmission lines in service or with a variety of lines out of service. For each computer simulation run, the transmission system voltage, transmission line loading, reactive support and other parameters are

[4] Reliability includes adequacy and security considerations. Adequacy evaluates whether or not there is sufficient transmission capacity to serve the load without violating criteria. Security evaluates whether or not the transmission system response will meet appropriate criteria (voltage, thermal, frequency, reactive margin, etc.) after a transmission element(s) becomes unavailable for service (e.g., a forced outage of a transmission line).

measured and compared to specific reliability criteria[5]. If the reliability criteria are not met, then appropriate mitigation (transmission and non-transmission) is modeled in the basecase database and the computer model simulation is run again. This process continues until the reliability criteria are met. The mitigation measures could include enhancements to the transmission system, generation development, demand resource development or other alternatives.

A database is developed that includes technical data for generation, transmission lines, electrical system equipment and customer load levels and geographic distribution. NWE will consult with the TRANSAC in developing forecast data for transmission, generation and demand response resources. The basic methodologies for developing this forecast data are described below.

- Transmission: NWE will use the existing transmission infrastructure as a starting point. This data will be reviewed and any updates to the existing transmission data will be included in the basecase. Future new additions to the transmission system may or may not be included. If a new transmission project is under construction, then it will be included in the base case. Future new transmission additions not under construction will not be included in the initial basecase unless a prior planning study has accepted the project and NWE agrees to include it after discussing it with TRANSAC. These projects may be included in some of the base and/or uncertainty scenarios and not others. Other future new transmission additions will be considered as one of the mitigation options should transmission system reliability problems arise during the study.

  New regional transmission projects that affect NWE's transmission will be included if the project is in Phase 2 of the WECC Three Phase Rating Process and NWE agrees to include it after discussing it with TRANSAC. These projects may be included in some of the base and/or uncertainty scenarios and not others.

- Generation: NWE will use the existing generation infrastructure as a starting point. This generation data will be reviewed and any updates or changes will be included in the basecase. Future generation additions, including generation from NWE's generation interconnect and transmission service request queue may be included. Since NWE currently has significantly more generation installed than load, proposed new generation additions may significantly change the transmission system configuration because of the mitigation requirements (i.e., transmission fixes) to connect and move power across NWE's transmission. The Transmission System Planning process cannot ignore this. NWE will review these potential new generation additions and their transmission fixes with TRANSAC and then consider including them into the base scenarios and/or uncertainty scenarios. It is likely that these new proposed projects might be included in some of the base scenarios and not others or may be included in the uncertainty scenarios only.

[5] Federal Energy Regulatory Commission, NERC, WECC or NWE reliability criteria.

- Demand Response Resources: NWE will obtain demand response resource forecasts directly from the LSEs and customers within the balancing area. TRANSAC and NWE will review these forecasts and then consider including them in the basecase. The uncertainty scenarios may adjust these forecasts.

Using this database information, NWE will develop the **basecases** that are used to model the transmission system. NWE's base case also includes this data for the entire WECC region. The time frame that the base case data represents is for a very specific condition that may occur over the course of the year. Thus, defining the conditions for a base case involves defining the generation, transmission configuration and customer load levels that are the focus of the study. In order to study each hour of a year, 8760 different base cases could be developed (8760 hours = 8760 basecases). This is impractical. Transmission planning's purpose is to ensure transmission system reliability under all operating conditions, which means that the studies need focus only on the conditions that may stress the system. The following two examples describe stressed system conditions:

Example 1: Montana load at peak load conditions, such as summer peak day, and high generation will stress the local area transmission system serving the local area load.

Example 2: Montana load at light load conditions, such as the middle of the night, with high generation levels and high export levels will stress the high voltage transmission system.

The technical analyses will use different engineering studies to evaluate the system performance. These studies are designed to use different engineering perspective to ensure system reliability is maintained. These methods include, but are not limited to, the following:

- Steady-State Powerflow Analyses
- Post Transient Steady-State Powerflow Analyses (or Steady-State Post Fault Analysis)
- Transient Stability Analyses (or Dynamic Analyses)
- Fault Duty Analyses
- Reactive Margin Analyses

A study of the transmission system under static conditions is a steady state powerflow study, and a study over time[6] is called a transient stability study. The steady state powerflow analysis is a static evaluation of a local area transmission system that

[6] The PSS/E model automatically completes a transient stability study by running the computer model repeatedly over time and recording how the generation and transmission elements change over time as the result of an outage. A sequence of results is produced that depict how the generation and transmission system equipment responds to this outage condition. The time step must be very small to accurately capture transmission system changes because generation and load are matched instantaneously. For example, a dynamic study runs a powerflow simulation of the system, with progressive "real" time adjustments, every ¼ cycle or 0.00417 seconds. Thus to make a 5 second study, the program must be run 1200 times.

examines the transmission system under normal operating conditions with all lines in service and with single and creditable multiple transmission lines or elements out-of-service (i.e., N-1, N-2, etc. conditions). Note that the "-1" in N-1 represents the number of transmission elements that are out of service. A transient stability study (i.e., a dynamic simulation study) evaluates the transmission system performance on a progressive time dependent basis. These studies evaluate credible outage events to determine if the transmission system will recover to acceptable steady-state operation after the outage. The studies include an assortment of outage events that are intended to provide a thorough test of the reliability of the transmission system. After a powerflow simulation is completed, a search of the simulation results for unacceptable thermal overload and voltage excursion is made. Unacceptable transmission system performance must be corrected by including transmission and non-transmission (e.g., demand-side resource, generation, etc.) fixes into a second simulation. Additional mitigation or fixes are included in the simulation until a valid solution is found. A valid solution is one that meets the reliability criteria describe below. Economic and system performance information for this scenario is identified and retained for comparative analysis between scenarios during the decision step.

The credible "worst case" single and multiple fault events must be simulated to determine if the transmission system will recover to acceptable steady-state operation. A dynamic simulation includes an assortment of outage events that are intended to provide a thorough test of the reliability of the transmission system.

Each scenario study must evaluate the effectiveness of existing Remedial Action Schemes ("RAS") within NWE balancing area. A RAS is used to maintain system reliability for voltage performance problems. These RAS include NWE's Acceleration Trend Relay ("ATR") device to trip generation at Colstrip for major events, the Bonneville Power Administration's RAS to directly trip the Miles City DC tie for certain 500 kV events west of Garrison and a RAS to trip the Hardin generation for certain 500 kV events. The Colstrip generation employs generator tripping for critical outage events on the 500 kV electric transmission system. The generator-tripping scheme is a computer-based relay called the ATR. This device monitors the generator speed and acceleration (real time), and digitally analyzes these quantities to determine when an unstable event is in progress. If an unstable event is in progress, the device determines the amount of generator tripping that is required to protect the electric transmission system from instability and unacceptable low-voltage swings caused by the event. The ATR then proceeds to trip the necessary number of generating units at Colstrip before the event causes instability problems to occur. To model the ATR in the study software requires special non-proprietary NWE software be used in conjunction with the PSS/E model.

In addition, as new generation is added to the existing generation sources, NWE must fully evaluate the impacts to the existing RAS operation and whether or not the new generation must be on a RAS. NWE may also consider an Overload Mitigation Scheme ("OMS") to control for thermal overloading. See the Criteria section for a more detailed discussion of the RAS and OMS use.

From these studies and analysis of the changes in system steady-state and transient voltage levels after the loss of a single line, multiple lines, or generating units; changes in the line and equipment thermal loading conditions; changes in Volt-Ampere reactive ("VAr") requirements (voltage support); and unacceptable frequency excursions are scrutinized. All relevant reliability criteria are applied in these evaluations. See the Criteria segment of this document for a discussion of NWE's criteria.

NWE will also conduct fault duty study and reactive margin studies as needed. A fault duty study is a study of electrical current interrupting devices (e.g., breakers) to ensure the device can open under maximum fault conditions. When a fault or short circuit occurs on a power line, the protective relay equipment detects the increased current (i.e., fault current) flowing in the line and signals the line's circuit breakers to open. When the circuit breakers open, they must be capable of interrupting the full fault current. The worst-case fault current is commonly referred to as the "fault-duty". A reactive margin study is a study to ensure that the transmission system has sufficient voltage control to maintain adequate voltage levels.

### Decision

An objective of a system planning study is to evaluate the range of potential transmission and non-transmission (e.g., demand side management, generation, conservation, etc.) solutions within the technical study and then use the results from the base studies and the uncertainty studies to make an informed decision. The decision rule, which will be developed for each transmission plan as describe below, can include quantifiable results (e.g., cost) and non-quantifiable information (e.g., written discussion of an issue). NWE's decision rule may include, but is not limited to, the following information:

- Total present value of utility costs
- System performance statistics to measure customer impacts
- Environmental assessment and/or costs
- Reliability metrics
- Uncertainty and Risk assessment results
- Non-quantifiable assessment
- Provide consistent, documented process

The primary purpose of the decision rule is to provide descriptive information (e.g., costs, risks, etc.) about the system and mitigation needed to resolve the problems. This information can be ordered or weighted so that stakeholders can understand the differences between the scenarios and provide input to NWE. NWE management can then use this information and input to make an informed decision for future transmission investment to serve future network load and point-to-point requests. Once approved, the mitigation will be prioritized into NWE's 15-year business plan.

### Reporting

The results of the transmission system plan will be reported and prioritized into NWE's 15-year business plan. Information from the transmission system plan will aid NWE management in this priority. It is NWE's intent to publish a formal report bi-annually, with the first report due early 2009.

## *Load Forecast Methodology*

NWE will use a peak load forecast that is based on a 50% probability of being exceeded (i.e., 1 in 2 assumption). The forecast may be adjusted up to a 1 in 10 or 1 in 20 (i.e., 10% and 5% probability, respectively) to capture a heavy peak load conditions. NWE will develop its load forecast from two sources. First, pursuant to FERC MOD 016, NWE will obtain load forecasts from Load Serving Entities ("LSE") within the balancing area. A 1 in 2 (50% probability of being exceeded) and a 1 in 10 (10% probability of being exceeded) summer and winter peak load forecast from the LSEs within the balancing area will be used. The LSE's peak load forecasts will be summed, assuming they are time coincident, to calculate the balancing area load forecast. NWE's second source is a regression-based peak load forecast model that NWE has maintained over the years. The loads within NWE's balancing area are metered and tracked. That is, the loads are well defined. If the LSE and NWE load forecast results are significantly different, NWE will attempt to reconcile these differences. If NWE cannot reconcile these differences, NWE will choose which forecast to use in the study.

The balancing area peak load forecast will be adjusted to reflect demand response resource reductions, conservation reductions and other appropriate peak load modifying sources.

Once a balancing area load forecast is developed, this forecast is disaggregated to the load buses in NWE's balancing area. There are two types of load buses – (1) a load bus where the load does not change over time (e.g., a single large industrial load bus); and (2) a load bus where the load changes over time (e.g., residential load). NWE uses its knowledge of load characteristics along with regression analysis to extrapolate the individual load bus data in time. The load bus forecasts are summed and compared to the balancing area load forecast. If the two forecasts do not match, NWE will adjust the changing load bus forecasts until the two forecasts are the same.

## *WECC Annual Study Program*

In addition to NWE's own transmission system planning study, NWE participates in the **WECC Annual Study Program.** This program examines the reliability of electric transmission lines that are instrumental in moving electricity across the NWE system from sources of supply inside and outside Montana to markets inside and outside Montana. These lines generally range in size from 100 kV through 500 kV. A detailed

simulation model[7] is used for steady state and dynamic event analysis that assesses electric transmission stability before and after a loss of a critical electrical element (e.g., line).

Two types of study assessments are conducted - **Operating Transfer Capability ("OTC")** studies and **Bulk System Planning Studies**. The distinction between these studies is that the OTC study establishes the next season's maximum transfer capacity for selected electric transmission path and the planning studies evaluate the bulk transmission system's adequacy and security 2-10 years into the future. The Annual Study Program requires that each year approximately ten detailed studies be conducted to assess bulk electric transmission reliability. The mix of operating and planning studies varies each year.

When conducting a seasonal **OTC study**, NWE follows the WECC policy of using a critical outage for a load condition and generation pattern defined by WECC to establish the OTC that meets reliability criteria. The specific load and generation patterns may include heavy winter or summer loads with maximum thermal generation and critical hydro conditions and light spring loads with maximum generation. The outages that are of interest may include single or double line loss of the critical lines. After completing a study, NWE looks within its system and outside its system for unacceptable voltage concerns, overloaded electrical equipment and frequency excursion. The equipment includes, but is not limited to, generators, transmission lines, transformers, series capacitors, wave-traps, circuit switchers, and circuit breakers. Other electrical equipment on the system may limit the transfer of power through a system; therefore, they need to be considered when conducting studies. Voltage levels are reviewed to make sure that the steady state, post-fault and transient voltage performances comply with all criteria. NWE checks for unacceptable equipment thermal loading, voltage swings and positive damping after transient excursions on a system-wide basis. See the Criteria section of this document for criteria requirements.

OTC studies are conducted by adjusting the load and generation patterns in a computer simulation model (i.e., PSS/E) to maximize the loading on the electric transmission path (e.g., set of branches being assessed). The initial generation, load, and transmission data are taken from an appropriate WECC base case. Assessments must evaluate the effectiveness of the RAS in NWE's balancing area. These RAS include NWE's ATR device to trip the Colstrip generation for major events, the Bonneville Power Administration's RAS to directly trip the Miles City DC tie for certain 500 kV events west of Garrison and the Hardin generation RAS. Maximum loading on the path is achieved when the system performance for the most sensitive parameter, either steady state or transient, just meets the reliability criteria. This establishes the OTC for that path. Planned equipment changes and/or additions are allowed in the study.

The **Bulk System Planning Study** originates through the WECC System Review Work Group ("SRWG") annual planning program. The WECC study follows the same process

[7] NWE models the WECC transmission system using the PTI PSS/E software. NWE base case data includes the 50 kV to 500 kV transmission system data.

as the OTC studies, except the season can range from 2 to 10 years in the future and may include proposed new facilities. The goal of the planning study is to examine the reliability of the future transmission system under prescribed seasonal loads, generation patterns, and various outage conditions and to identify appropriate upgrades and/or new facilities to maintain bulk system reliability into the future.

## *Economic Planning Study*

Pursuant to FERC Order 890, stakeholders may request an Economic Planning Study. The purpose of FERC Order 890 Economic Planning Studies is to ensure that customers may request studies that evaluate potential upgrades or other investments that could reduce congestion or integrate new resources and loads on an aggregated or regional basis (e.g., wind developers), not to assign cost responsibility for those investments or otherwise determine whether they should be implemented. This is different than a proposed new generation interconnect study in that an interconnect study is to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider's Transmission System.

A request for an Economic Planning Study may be confined to NWE's balancing area, in which case NWE would complete the study using the methodology, criteria and process described within this document. A request for an Economic Planning Study may be included as a scenario in NWE's biannual Transmission System Plan cycle if it is received in a time that would allow this inclusion. If the request is received at a different time, then NWE will process the request using methodology and process similar to the process described herein.

If a request for an Economic Planning Study expands beyond NWE's balancing area, then the request will require sub-regional or regional study process and NWE will coordinate this with the Northern Tier Transmission Group ("NTTG") or to WECC. NWE will coordinate and participate in their Economic Planning Study as required.

# Criteria

NWE reliability criteria, NERC/WECC[8] regional reliability criteria (hereafter called WECC Standards), FERC[9] Standards and industry standards (e.g., IEEE Standards) are the basis for NWE transmission planning criteria. This section describes these criteria.

## *Reliability Criteria*

Electric transmission reliability is concerned with the adequacy and security of the electric transmission system. Adequacy addresses whether or not there is enough transmission, and security is the ability of the transmission system to withstand contingencies (i.e., the loss of a single or multiple transmission elements).

- NWE Internal Reliability Criteria is a set of technical transmission reliability measures that have been established for the safe and reliable operation of NWE's transmission system.

- The FERC Standards and the WECC Standards set minimum performance standards for voltage excursions and voltage recovery after a credible outage event on the transmission system.

NWE uses these criteria in evaluating a change or addition to its electric transmission equipment and/or a change or addition to load or generation. NWE will use these reliability criteria as needed to fully evaluate the impacts to its electrical system of proposed lines, generation or loads. NWE augments these criteria with other standards such as, but not limited to, the ANSI and IEEE standards.

NWE planning ensures that any change that either directly or indirectly affects its transmission system will not materially reduce the reliability to existing customers. The NWE electric transmission system must remain dependable at all times so that it may provide reliable high quality service to customers.

### NWE Internal Reliability Criteria

NWE Internal Reliability criteria are used for reliability performance evaluation of the electric transmission system. Steady state implies the condition on the transmission system before an outage, or after an outage and after switching occurs, regulators adjust, reactors or capacitors switch, and the electrical system has settled down (typically three minutes or more). This latter condition is also called post-fault reliability requirements.

NWE's criteria include a collection of ANSI standards as well as past and current practices, that when applied with experienced engineering judgment, lead to a reliable

[8] WECC is in the process of removing standards that duplicate the FERC Standards; so only the more stringent WECC criteria will remain.
[9] The FERC Standards are implemented by NERC.

and economical electric transmission system. These criteria support the FERC Standards and WECC Reliability Criteria that disallow a blackout, voltage collapse, or cascading outages unless the initiating disturbance and corresponding impacts are confined to either a local network or a radial system. An individual project or customer load may require an enhanced reliability requirement.

NWE plans for a transmission system that provides acceptable voltage levels during system normal conditions and outage conditions. Areas of the NWE system that are served by radial transmission service are excluded from single contingency evaluation, due to economic considerations.

***Steady State and Post Fault Voltage Criteria for 230 kV and Below***

The steady state voltage criteria listed in the tables below are based on the assumption that all switching has taken place, all generators and transformer Load Tap Changer's ("LTC") have regulated voltages to set values, and capacitors or reactors are switched. The basis for the percent voltages is the designed operating voltage.

As shown in Table 1, the recommended upper voltage limit for a load-serving bus is 105% unless equipment rating dictates a different limit. NWE follows the limit as outlined in the American National Standards Institute (i.e., ANSI C84.1). It is possible that a load-serving bus voltage may exceed the tabled value if conditions allow a higher voltage without harm to NWE or customer equipment.

Table 1
Maximum Upper Voltage Criterion
At Unregulated Load-Serving Bus

| | Upper Operating Limit |
|---|---|
| Voltages | 105% |

The allowable minimum percent voltage for any load-serving bus that is within a network configuration is shown in Table 2. It is possible that a load-serving bus voltage may fall below the tabled value if conditions allow a lower voltage without harm to NWE or customer equipment. This table will be applied on busses that are not part of the bulk electric system where bulk electric system reliability is not affected. Otherwise the FERC/NERC and WECC criteria are applied to the bulk electric system busses.

| Table 2<br>Minimum Allowable Percent Voltage<br>At NWE Unregulated Load-Serving Bus | | | |
|---|---|---|---|
| Nominal Voltage | Existing System (N-0) | First Contingency (N-1) | Second Contingency (N-2) |
| 230 kV and 161 kV | 97% | 95% | 93% |
| 115 kV and 100 kV | 95% | 93% | 90% |
| 69 kV and 50 kV | 93% | 93% | 90% |
| Note:<br>1. Percent voltage is measured from the nominal voltage.<br>2. The 50, 69 kV and 100 kV are not bulk electric system elements. | | | |

The minimum allowable percent voltage for a load serving bus that is on a radial transmission system for an event on the radial line must only meet the existing system performance (N-0) shown in Table 2. Any unacceptable voltage performance must be mitigated in accordance with the criteria described below. The use of a Remedial Action Scheme (RAS)[10] will be evaluated on a case-by-case basis, with no assurance that NWE will accept or use a RAS. Table 2 assumes that all other methods to control voltage have been explored (such as capacitors, reactors, and line switching, etc.).

### *Steady State Voltage Criteria for 500 kV*

The allowable operating voltage range for the 500 kV transmission system is 100% to 110% of nominal, or 500 to 550 kV. (It should be noted that the nominal rated voltage of all "500 kV" equipment is 525 kV; therefore the acceptable range of voltages for this portion of our system is 500-550 kV.)

### *General Minimum Equipment Specifications*

Table 3 summarizes the MVA, voltage, current, BIL level, MCOV and interrupt ratings of equipment as applicable and associated grounding requirements. The general minimum specifications for NorthWestern Energy Transmission and Substation equipment are listed in the following table.

[10] Also known as Special Protection System (SPS)

Table 3

Transmission and Substation Equipment: General Minimum Specifications

| | Nominal System Voltages - kV | | | | | |
|---|---|---|---|---|---|---|
| | 230 kV | 161 kV | 115 kV | 100 kV | 69 kV | 50 kV |
| MVA and Current Ratings *(1) | As Req'd | As Req'd | As Req'd | As Req'd | As Req'd | As Req'd |
| Equipment BIL (kV) *(2) | 900 | 750 | 550 | 550 | 350 | 350 |
| Maximum Design Voltage (kV) *(3) | 242 | 169 | 121 | 121 | 72.5 | 72.5 |
| Breaker Interrupt Current (kA) | 40 | 40 | 40 | 40 | 40 | 40 |
| Breaker and Switch Continuous Current (A) *(4) | 1200 | 1200 | 1200 | 1200 | 1200 | 1200 |
| Arrester Duty Rating/MCOV (kV) *(5) | 172/140 | 120/98 | 90/70 | 90/70 | 54/42 | 39/31.5 |
| Substation Insulator Class | TR-304 | TR-291 | TR-286 | TR-286 | TR-216 | TR-214 |
| Transmission Line BIL, wood (kV) *(6) | 1105 | 780 | 610 | 525 | 440 | 355 |
| Transmission Line BIL, steel (kV) *(7) | 1265 | 945 | 695 | 610 | 525 | 440 |

*Notes:

1. Project and equipment specific as required to avoid thermal overloads
2. 1050 kV BIL is also used on some 230 kV equipment
3. At least 5% over nominal
4. 2000 amp equipment is used in some applications
5. For effectively grounded systems
6. Insulator support hardware ungrounded
7. Insulator support hardware grounded

### *Transmission Equipment Rating and Loading*

**Transmission Conductors:**

Transmission conductor continuous rating is based on 25°C (77°F) ambient air at 1.4 mph (2 ft/sec), 50°C conductor temperature rise, and 75°C (167°F) maximum operating temperature unless conditions dictate otherwise (i.e., some conductors and lines may be specifically designed for higher operating temperatures). This is Rate A in the powerflow base cases. Unacceptable conductor loading can be mitigated by system improvements or, in some cases, an Overload Mitigation Scheme ("OMS") that changes system conditions to mitigate the overload. The use of an OMS will be evaluated on a case-by-case basis, with no assurance that NWE will accept or use an OMS.

**Transformers:**

Transformer rating is based on the following:

- For standard service conditions (24 hour average ambient air temperature of 30°C or 86°F, or less), the continuous rating is 100% of the highest operational nameplate rating. This is Rate A in the load flow power case.

- For winter service conditions (24 hour ambient air temperature less than 0°C, or 32°F,) loading to 125% of the standard service condition rating may be allowed.

Unacceptable transformer loading can be mitigated by transformer replacement, system improvements or, in some cases, an OMS that changes system conditions to mitigate the overload. The use of an OMS will be evaluated on a case-by-case basis, with no assurance that NWE will accept or use of an OMS.

**New Facility (Generation, Transmission, Load, or Line):**
The primary goal when interconnecting a new facility to NWE's transmission system is to ensure that the configuration of the interconnection will not materially reduce the performance of the transmission system or the reliability of service to customers. A material reduction in reliability occurs when operation associated with a new facility or the interconnection itself precludes complying with NWE criteria, WECC criteria, FERC Standards or good utility practice. System reliability cannot be jeopardized as a result of connecting a new or up-graded facility. Steady state and transient electric transmission system performance must meet or exceed NWE, FERC and WECC performance criteria, and changes in fault duty cannot exceed equipment capability. Any unacceptable system performance (voltage, thermal, frequency, fault duty, PV/QV, power quality, etc.) must be mitigated prior to interconnection.

The addition of new generation to NWE transmission system, including induction machine generation, must not cause unacceptable voltage fluctuations (i.e., a flicker problem) or harmonics as the units operate or as the generators cycle on and off during marginal operating conditions. New generation connected to NWE's electric transmission system shall comply with the limits set by IEEE Standard 519. A high-speed dynamic responsive reactive device (e.g., STATCOM, Static Compensator) must be provided to protect against flicker unless it can be demonstrated that the new generation does not cause a flicker problem. Instead of a high-speed dynamic responsive device, it might be proven that a different solution, such as managing individual wind turbine generation starts through a master control system, solves the flicker problem.

At the Point of Interconnection, NWE requires an interconnection facility to be able to produce or absorb Reactive Power between 0.9 leading to 0.9 lagging power factor to meet voltage schedules set by NWE within a range of 0.95 to 1.05 of nominal.

Induction generators are assumed to have operational characteristics either through internal or external capabilities to operate throughout a power factor range of 0.95 leading to 0.95 lagging at the Point of Interconnection.

***Remedial Action Scheme (RAS) and Overload Mitigation Scheme (OMS) Application***

NWE may consider a RAS or an OMS application to protect the electric transmission system against certain types of events, but each application will be evaluated on a case-by-case basis with no assurance that a RAS or an OMS application will be acceptable.

- An OMS may be used to mitigate a thermal overload that is less than the thermal rating of a system element by tripping or by generator run-back.

This may be an appropriate application for an overload that results from a single (or multiple) contingency outage event. The OMS may be manual (with a response time not greater than 30 minutes) or automated (with a faster response time). Typically, response time for an OMS application is measured in tenths of seconds to minutes. Generally, an OMS can be thought of as a scheme that can be backed up by relay operation or operator intervention if necessary. An OMS will not be considered as acceptable mitigation for system element overload if its failure to operate properly could lead to widespread outages on the Bulk Electric System.

- A RAS may be used for certain single and multiple contingency outage events that result in unacceptable electric system reliability performance that is not related to minor thermal overloading and that requires a more immediate response (e.g., unacceptable transient stability performance). A RAS must be an automated response to the outage. Typically, response time for a RAS application is measured in cycles or at most a few seconds. While the ranges of expected response times may overlap, there is a distinctly different character to a RAS. It may be expected to meet a higher reliability standard, depending on the application. There is no expectation that a transmission system operator could intervene if the RAS were to fail to operate. Any RAS application must be redundant and meet WECC system planning criteria. NWE will submit any RAS application that may be proposed to the WECC RASRS for their approval if the RAS failure could lead to widespread outages on the Bulk Electric System of the Western Interconnection. If a RAS does not receive the approval of the RASRS, NWE will not use it.

NWE's criterion for the use of a RAS or an OMS is consistent with the performance requirements of existing facilities connected to NWE transmission system. NWE's criterion is stated below:

- All lines and equipment in service:
  - OMS application with Conditional Firm Transmission Service: NWE may consider an OMS for thermal overloads with all lines and equipment in service for generation resources receiving Energy Resource Interconnection Service ("ERIS") and submitting an application for Conditional Firm Service if the overload condition is well-defined, is not acute (i.e., study results do not exceed 125% of transformer or 100% of line ratings without mitigation for one or two elements), and is isolated to the local area transmission. The ability to control the overload must be simple, and the OMS must completely eliminate the overload in a time specified by NWE with no impact to third party customers. An assessment will be made on a case-by-case basis with no assurance that an OMS will be acceptable. The equipment to control the generation output must be automated, redundant (with no common point of failure), set to execute mitigation procedure below 100% of thermal capability as specified by NWE, and NWE must also have automated control of a breaker that can be used to trip the facility (or a sufficient portion of the

facility) off-line to eliminate the overload completely should the redundant control equipment fail to perform as designed.

- N-1 Outage: For single contingency (N-1) conditions with a new facility (i.e., generation, transmission, load, line, etc.) connected, unacceptable system performance must be mitigated.

  - N-1 RAS Application: Any RAS application to mitigate for an N-1 outage should be comparable to other RAS applications on NWE's system. NWE has not had a RAS operation from its Acceleration Trend Relay ("ATR") at Colstrip caused by any N-1 line outage. Studies show, however, that the current ATR design may call for RAS unit-tripping under high Colstrip generation levels and high transmission loading conditions coupled with a single 500 kV three-phase line fault. A three-phase line fault has a very low probability of occurrence (there has never been a three-phase fault on the Colstrip 500 kV system). NWE may consider a RAS for an N-1 three-phase line fault, but this will be evaluated on a case-by-case basis with no assurance that the RAS application will be acceptable. NWE will not consider a RAS application as an acceptable mitigation for any N-1 condition caused by anything other than a three-phase fault (e.g., no fault, single-phase outage, two-phase outage, phase-to-phase outage, etc.). Any RAS application must be redundant and meet FERC/NERC/WECC system planning criteria. NWE will require that the WECC Remedial Action Scheme Reliability Subcommittee ("RASRS") approve any RAS application that may cause widespread outages if the RAS fails to perform as designed.

  - N-1 OMS application for line overloads: Using an OMS may be acceptable to mitigate (i.e., reduce overload) for a thermal overload condition caused by a single contingency. Each overload situation will be evaluated on a case-by-case basis with no assurance that NWE will choose to apply an OMS instead of system changes or enhancement. In all instances, an OMS must:
    - Limit loading to below 100% of rated capacity;
    - Allow no accelerated loss of life, or degradation of utility equipment per accepted industry standards and/or good utility practice;
    - Maintain a safe system;
    - Limit conductor loading to not exceed the conductor's maximum design.

  - N-1 OMS application for transformer overloads: Using an OMS may be acceptable to mitigate (i.e., reduce the overload) for a transformer thermal overload condition caused by the loss of a single system element (i.e., line, parallel transformer, etc.). Using an OMS for transformer overloads may be applied if the overload does not exceed 125% of transformer per unit rating. For transformer overloads greater than 125%, an OMS is unacceptable mitigation. In all instances, an OMS must:
    - Limit the overload duration to less than 30 minutes;

- Maintain a safe system;
- Allow no accelerated loss of life, or degradation of utility equipment per accepted industry standards and/or good utility practice.

- N-2 (double or greater) Outage: NWE may accept an OMS for thermal overloads or a RAS as the primary mitigation for an N-2 (or greater) outage condition. Each application would be evaluated on a case-by-case basis with no assurance that NWE will choose to utilize an OMS or RAS scheme instead of system changes or enhancement. Any application may be required to be redundant and must meet FERC Standards and WECC criteria.

  Any RAS application must be redundant and meet WECC system planning criteria. NWE will require that the WECC RASRS approve any RAS application that may cause widespread outages if the RAS fails to perform as designed.

  NWE may consider an OMS for a credible N-2 (or greater) outage condition. Each OMS application will be evaluated on a case-by-case basis with no assurance that the OMS application will be acceptable. Any N-2 OMS application may be required to be redundant.

- RAS Application for a Stuck Breaker: NWE may consider a RAS application to mitigate for a stuck breaker contingency. Each RAS application will be evaluated on a case-by-case basis with no assurance that the RAS application will be acceptable. Any RAS application must be redundant and meet WECC system planning criteria. NWE will require that the WECC RASRS approve any RAS application that may cause widespread outages if the RAS fails to perform as designed.

- RAS Application for a Transformer Outage: NWE may consider a RAS application to mitigate for a transformer outage. However, it is recognized and may not be acceptable because application of a RAS for the catastrophic loss of a transformer could require the local system operations to be reduced until a suitable transformer is installed. Each RAS application will be evaluated on a case-by-case basis with no assurance that the RAS application will be acceptable. Any RAS application must be redundant and meet WECC system planning criteria. NWE will require that the WECC RASRS approve any RAS application.

### *Voltage Ride Through*

NWE will follow FERC and WECC high and low voltage ride through criteria as appropriate. Under certain circumstances, NWE may require the generation to trip offline to maintain system reliability instead of riding through the event.

### *Harmonics*

Because some generation facilities, such as wind generation, may include large capacitor banks to supply adequate voltage support, and power electronic installations to accommodate the induction generators that are used for such facilities, and because both

such facilities may introduce harmonic currents either due to resonances at harmonic frequencies or through inverter circuitry that is capable of introducing harmonic currents, NWE may require a study be conducted to evaluate the potential for unacceptable levels of harmonic currents that may be introduced by the facility. This study should be performed along with the Facilities Study for the project. NWE will supply the system Thevenin equivalent impedance of its power system at the Point of Interconnection for the purpose of completing this study. This can be used to verify that no harmonic of the system frequency will be above acceptable levels [see IEEE standard 519-1992 and ANSI standard C84.1-1989]. The project will be required to mitigate any harmonics levels outside of acceptable limits.

***Subsynchronous Resonance***

The 500 kV transmission lines from Colstrip to Broadview to Garrison (and to the west) are series compensated. For this reason, the addition of a new generation project may require additional study to evaluate the exposure of each generator connected directly to or near this system. A Subsynchronous Resonance ("SSR") study will need to be commissioned by the various project sponsors to evaluate generator risk, not only for the new project, but also for all generators currently connected to NWE's electric transmission system. NWE welcomes the opportunity to participate in the SSR studies.

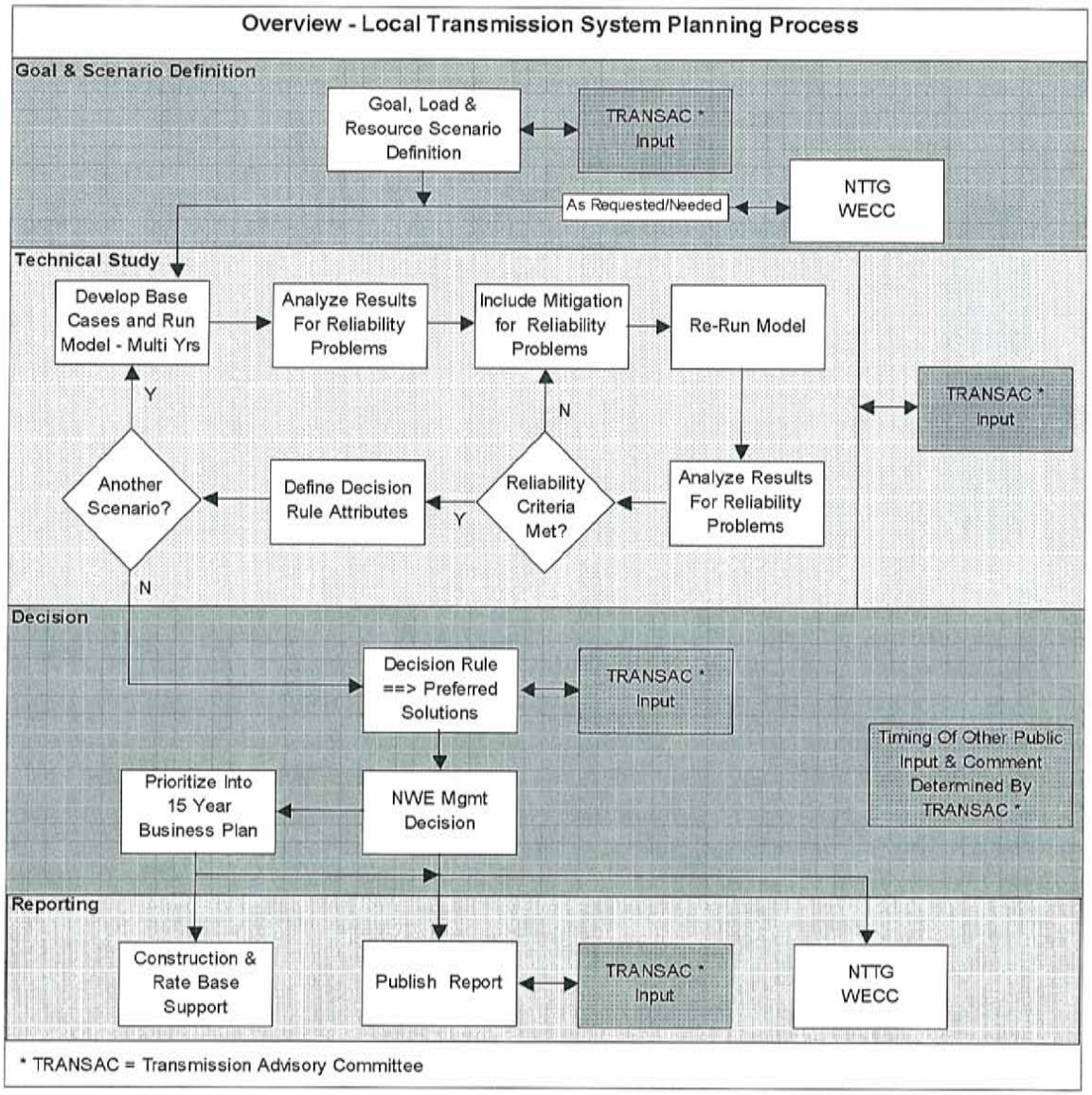
## FERC Standard Requirements and WECC Reliability Criteria

The FERC Standards and the WECC Reliability Criteria are used to evaluate NWE's Bulk Electric System performance under steady state and transient stability and the recovery performance of NWE's transmission system. These criteria apply to all of NWE's bulk electric transmission lines. See the latest standards posted on the NERC or WECC websites at http://standards.nerc.net and http://www.wecc.biz.

# Process Detail

NWE's local transmission system planning process is depicted in the following flowchart.

## *NWE Local Transmission System Planning Process*




NWE will follow a biannual cycle to complete the above process. This process will be used to develop a 15-year electric transmission system plan. The methodology steps (i.e., scenario definition, technical study, decision and reporting) are weaved together by this process to produce NWE's electric transmission system plan.

## Timeline

The typical timeline for NWE's two-year planning process cycle is shown in the following table.

Typical Timeline - NWE Transmission System Planning Cycle

| | | | Data Collection To Include In Study | | |
|---|---|---|---|---|---|
| | Quarter | Planning Steps | Open | Optional | Outside |
| Prior Cycle | Qtr 5 | | | | |
| | Qtr 6 | | | | |
| | Qtr 7 | | x | | |
| | Qtr 8 | | x | | |
| Current Planning Cycle | Qtr 1 | Goal & Scenario Definitions | x | | |
| | Qtr 2 | Technical Study | | x | |
| | Qtr 3 | | | x | |
| | Qtr 4 | | | | x |
| | Qtr 5 | | | | x |
| | Qtr 6 | | | | x |
| | Qtr 7 | Decision | | | x |
| | Qtr 8 | Reporting | | | x |

This timeline displays the approximate time dedicated to each of the planning steps and time when forecast data will be collected. Data that is collected will fall into one of three time periods for inclusion into NWE's planning process - "Open", "Optional" or "Outside". All data collected during the Open time period will be included in the study assuming the data is complete. Data obtained during the Optional time period may or may not be included in the study if it is not complete or the Technical Study has progressed to a point where including this information is not practical. NWE will consult with TRANSAC in making this determination. Forecast data will be collected for a 15 year period. Data collected during the Closed time period of the biannual cycle will be compared to the data used in the technical analysis and any notable changes will be discussed in the transmission system planning report.

## Goal and Scenario Definition

NWE will work with TRANSAC to establish the goal of the transmission plan. This goal should support the various stakeholder interests. The scenarios will be developed using this goal as a basis.

Armed with this goal, NWE will define the planning scenarios with input from TRANSAC. A scenario will depict a specific condition such as the peak summer load, maximum balancing area generation and maximum export to the northwest. This scenario represents a "snapshot" in time that is to be studied. Since there are a large

number of combinations of load, generation and export/import conditions, careful consideration must be given to design each scenario to depict a future load and generation dispatch pattern that stresses the transmission system. Transmission system reliability planning is about ensuring the transmission system remains reliable under all operating conditions.

Varying the amount, type and location of generation, balancing area load level and NWE export/import conditions are important in defining a scenario. Defining a scenario can include, but is not limited to, the following:

- Different types of generation to determine how generation response to outage conditions
- Generation location and magnitude to determine transmission stress
- Higher generation levels to cause more power to be exported out of the balancing area
- Lower generation levels with high imports from the east moving to the northwest to stress import paths
- Higher balancing area load to stress the local area transmission used for load service
- Lower the balancing area load levels with high generation to stress the high voltage transmission

As can be seen in the preceding flowchart, NWE's process includes input from NWE's advisory committee, TRANSAC, in defining the scenarios. The TRANSAC will provide input into NWE transmission planning process pursuant to FERC Order 890 Transparency requirements. Information regarding NWE's TRANSAC can be found on NWE's OASIS Website at http://www.oatioasis.com/NWMT/ under the Transmission Planning tab.

### Technical Study

Once the scenarios are defined, the technical study will begin by developing a base case that specifies the modeling information for the scenario condition. Each scenario may include several base cases to span the 15-year study horizon. For example, to study the summer peaks in 2010 and 2015 requires two distinct base cases that reflect the load, generation and transmission line and equipment changes and additions for the specific year. Developing a base case depicting the scenario is critical and can take a significant amount of work and time to develop. A 15-year study for a scenario may actually include only three base cases representing years 5, 10 and 15. These base cases will differ by the load growth, generation and transmission assumptions.

Once a base case is built, running the computer software to simulate the interactions between load, generation and transmission that instant in time provides the engineering statistics to evaluate transmission system performance. The transmission system performance (voltage, thermal, etc) is analyzed to identify whether or not reliability requirements have been met. If inadequate performance is observed, a mitigation measure (e.g., transmission or non-transmission) is defined, and the base case is modified to include the mitigation. The simulation is repeated and system performance is compared to reliability requirements. This circular process is repeated until the system

performance meets or exceeds reliability requirements. ***Note, that at the conclusion of the study only a single mitigation solution will be defined and implemented, so once a mitigation measure is defined for a scenario, it must be included in all scenarios to ensure that it works for all scenarios.***

The results of the above process yield a valid plan from which various statistics can be defined and included in a decision rule. NWE's TRANSAC will help define the decision rule attributes. The decision rule attributes can include, but are not limited to, the following:

- Total present value of utility costs
- System performance statistics
- Environmental assessment and/or costs
- Reliability metrics
- Non-quantifiable assessment

### Decision

Information from the base case scenarios and associated risk scenarios will establish a set of descriptive system performance information for each scenario. NWE will seek input from the TRANSAC in identifying the specific attributes to include in the decision. This information will be applied into a decision rule to describe each scenario's positive and negative aspects. The planning process will use quantifiable and non-quantifiable descriptors to describe the plan. One logical organization would be to develop a matrix that has attributes listed down the left column and the scenario and underlying mitigation across the top two rows. Each cell would provide a discussion or assessment for that scenario's attribute.

The primary purpose of the decision rule is to provide information about the system problem and mitigation to resolve the problem. NWE management can then use this information to make an informed decision for future transmission investment to serve future network load and point-to-point requests. Once approved, the mitigation will be prioritized into NWE's 15-year business plan.

### Reporting

NWE will develop a report for the above information. This report will describe the scenarios, technical studies, decision rule attributes and how the plan was developed. With the aid of TRANAC, NWE will make every attempt to clearly describe the methodology, criteria, and process that clarify how the transmission plan was developed.

## *Regional & Sub Regional Participation*

NWE's participation in regional and sub regional planning activities will be broad, ranging from providing data to participating in studies and committees. NWE electric transmission system data, assumptions and plan will be shared with interconnected transmission systems, sub regions and region entities. NWE's base case data and NWE

electric transmission system plan will be provided to the interconnect transmission system when appropriate.

NWE provides its transmission system plan's data and assumptions to sub-regional and regional committees[11] that are responsible for building databases and then using this database for load and resource assessments and for operating and planning reliability studies. This is an annual process that requires NWE to provide basic transmission data, balancing area load forecast and generation information to be shared and included in the databases used by regional and sub-regional planning entities. NWE will participate in these forums as appropriate.

NWE's will provide its electric transmission system plan to WECC, Northern Tier Transmission Group ("NTTG"), and other sub-regional entities as appropriate. In the sub-regional context, NWE is an active member of NTTG. NWE will submit its data, assumptions and transmission plan to NTTG as required for inclusion in the sub-regional transmission plan. NWE will actively participate in the NTTG planning process to ensure data and assumptions are represented in the NTTG sub-regional plan. Once NTTG's sub-regional plan is developed, NTTG will coordinate its plan with other sub-regional entities and with WECC. In the region, NWE's plan will coordinate through the NTTG sub-regional plan to the WECC regional plan. When appropriate NWE will provide its transmission plan information to WECC. NTTG's plan will be shared and coordinated within the WECC plan with other WECC sub-regional plans.
NWE will participate in sub-regional and regional transmission planning studies as appropriate to ensure data and assumptions are coordinated. These studies may be focused on integrating new transmission line(s) into the regional transmission network or a broad planning study of regional or sub-regional transmission needs. NWE's participation in these studies will be guided by the intent of the study and how NWE's electric transmission system might be affected.

NWE will also participate in regional or sub-regional studies to identify enhancements that could relieve "significant and recurring" congestion. In the past NWE participated in Northwest Power Pool, RMATS and WECC studies that focused on a broader footprint than NWE's balancing area. In the future, NWE will work closely with the NTTG and WECC process to identify congestion.

[11] For example: WECC System Review Work Group (SRWG), WECC LRS Subcommittee, and Northern Tier Transmission Group Planning Committee, etc.

# APPENDIX A-5-D

APPENDIX A-5-E

NorthWestern™ Energy

# *Mountain States Transmission Intertie ("MSTI")*

## *Phase 1 Comprehensive Progress Report*

*March 28, 2008*

# APPENDIX A-5-E

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# Executive Summary

NorthWestern Energy ("NWE") plans to build a 500 kV transmission line approximately 460 miles long. The line, called the Mountain States Transmission Intertie ("MSTI"), will be built between Townsend, MT, and Midpoint substation in southern Idaho. MSTI will be a series compensated transmission line, with a phase shifting transformer ("PST") to control power flow.

The northern terminus of MSTI will be a new 500 kV substation called Townsend. It will tap two existing 500 kV transmission lines between the Broadview substation, and the Garrison substation. The southern terminus of MSTI will be Midpoint—an existing 500 kV substation in southern Idaho. A substation for the PST will be built at or near the existing Mill Creek substation, in southwest Montana. Series capacitors will be located at Midpoint substation, and Mill Creek substation. (See Figure 1.)

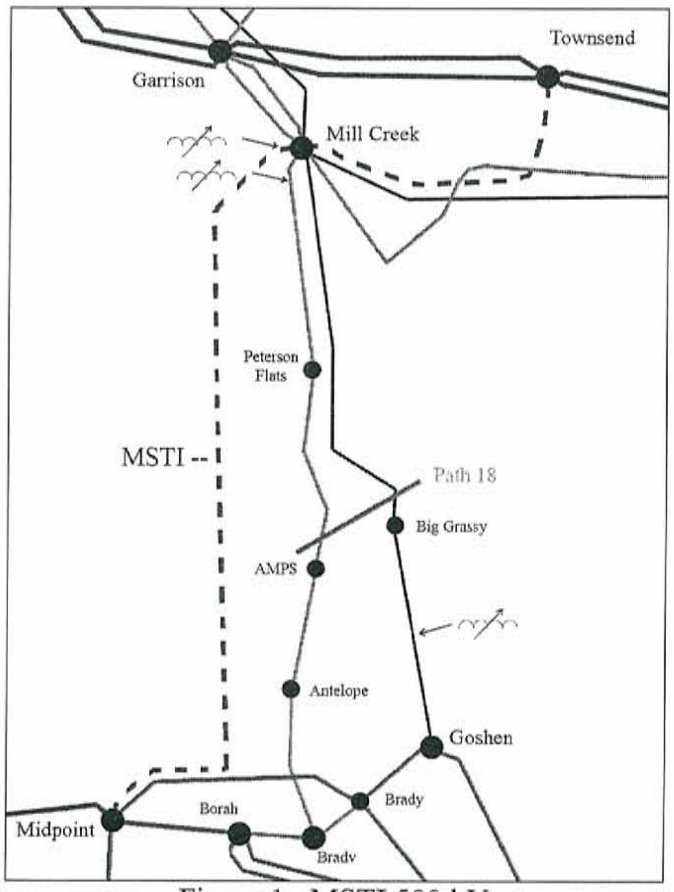


Figure 1. MSTI 500 kV

MSTI will be built to meet transmission service requests from customers, and to relieve constraints on the regions' existing transmission system. In addition, MSTI will accomplish the following:

- Improve transmission system reliability,
- Meet the growing demand for electricity,
- Provide regional energy diversification, and
- Develop a positive economic impact for the area.

This study was completed while following all regional planning and project rating review guidelines and requirements. The results of this study show that MSTI also meets all applicable NERC and WECC standards. MSTI has a planned in-service date of 2013. NorthWestern Energy believes that it has conformed to the guidelines in the WECC Path Rating Process.

# Introduction

## *Regional and Sub-Regional Participation:*

In an effort to address WECC guidelines, NWE is participating in the Northern Tier Transmission Group ("NTTG") Fast Track process. Through the Fast Track process, MSTI is coordinated with other regional and sub-regional projects. This helps ensure that MSTI:

- Takes multiple project needs and plans into account,
- Cooperates with other projects to identify broader regional needs,
- Takes planned resources of the region into account,
- Seeks input from stakeholders, and
- Coordinates with potentially parallel or competing projects.

## *Fulfillment of Need:*

This study demonstrates that the proposed MSTI 500 kV project meets all NERC and WECC Planning Standards. The Phase 1 study effort shows that MSTI fulfills the need for new transmission, and reduces existing system constraints.

# Project Description

MSTI will form a 500 kV connection between southwest Montana and southern Idaho. The northern interconnection point will tap two existing 500 kV transmission lines near Townsend, MT. The southern interconnection point will be at the Midpoint 500 kV substation. An additional substation will also be built near the existing Mill Creek substation. The new Mill Creek 500 kV substation will be built to accommodate a phase shifting transformer and series capacitors.

MSTI has a proposed N-S rating of 1500 MW. Power-flow and angle stability studies show that a 1500 MW N-S rating is possible during a heavy load condition. The N-S rating can be achieved by re-dispatching generation in Montana to export an additional 1500 MW, while increasing imports in California, Nevada, and Utah.

MSTI has a proposed S-N rating of 950 MW. This rating can be accomplished during light load conditions by decreasing exports in Montana and the Northwest, while increasing generation in Utah and Wyoming.

The following items are illustrated in Figure 2.:

- Proposed path for MSTI.
- Existing high voltage transmission system.
- Paths adjacent to MSTI
- NWE's control area.
- Location of PST.

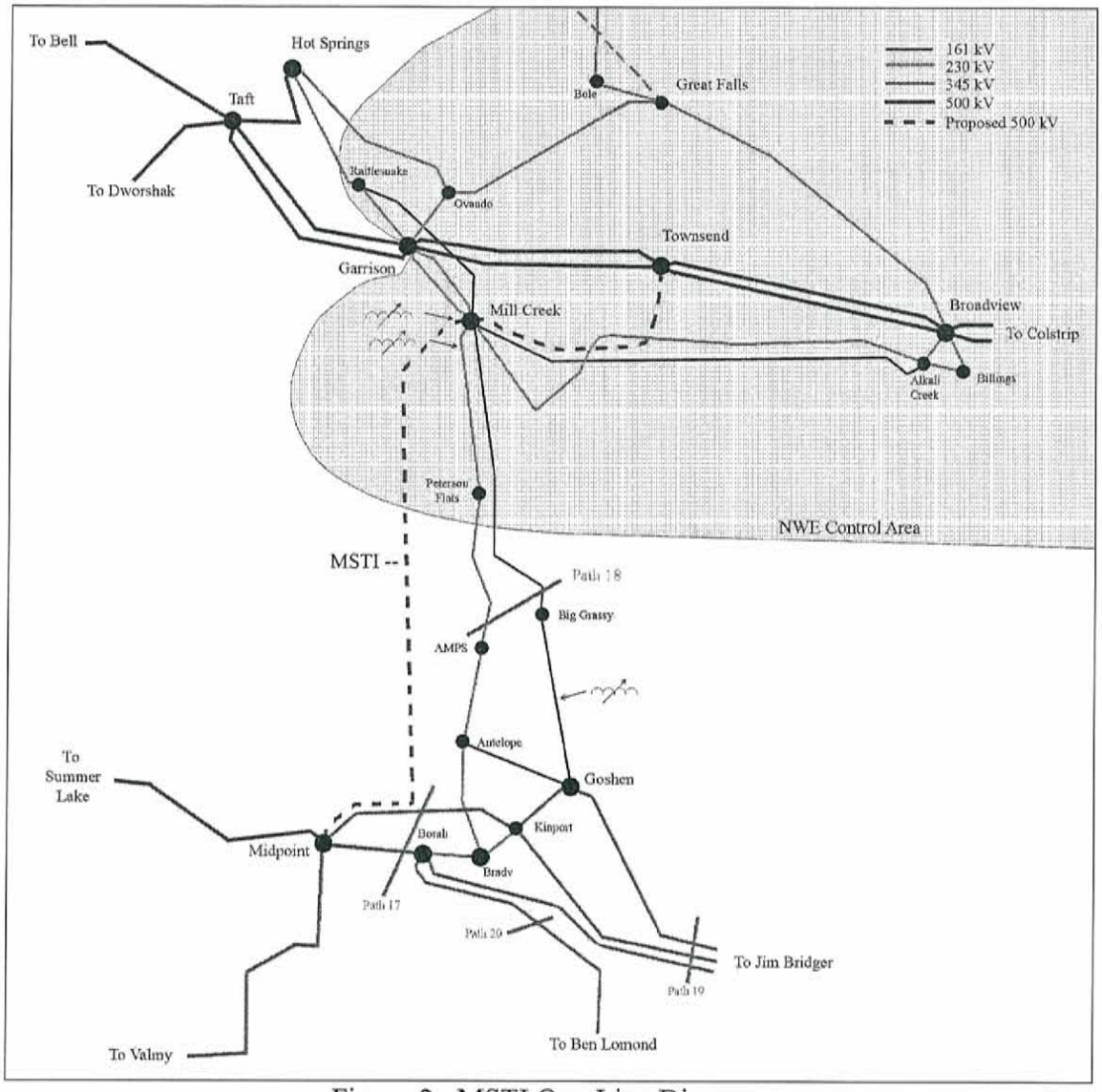


Figure 2. MSTI One-Line Diagram

# Project Milestones and Timeline

MSTI Milestones:

- WECC RPP Phase 1—Start: May 17, 2007; Complete: May 27, 2008
- WECC RPP Phase 2—Start: May 20, 2008; Complete: May 31, 2009
- WECC RPP Phase 3—Start: May 31, 2009; Complete: December 31, 2012
- MFSA Application—Start: January 1, 2007; Complete: December 31, 2008
- NEPA/MEPA Scoping—Start: January 1, 2007; Complete: December 31, 2008
- EIS—Start: January 1, 2009; Complete: December 31, 2009
- ROD/ROW Grants—Start: June 1, 2009; Complete: June 1, 2010
- ROW Acquisitions—Start: January 1, 2009; Complete: December 31, 2010
- Project Engineering—Start: January 1, 2007; Complete: December 31, 2010
- Project Construction—Start: January 1, 2010; Complete: December 31, 2012
- In Service Date: 2013

Figure 3 shows a timeline for the study process.

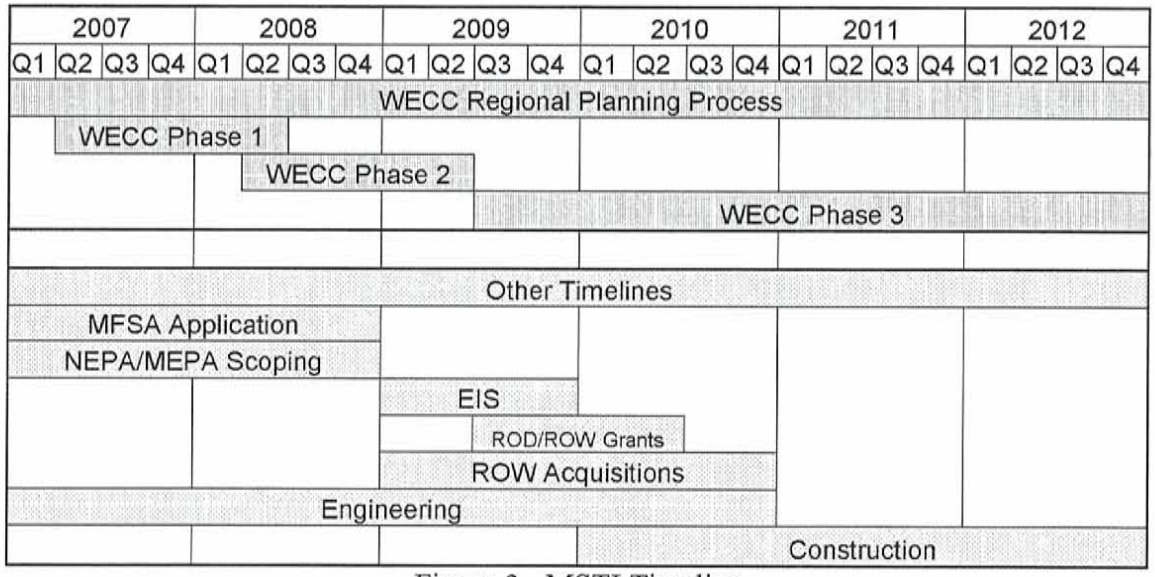


Figure 3. MSTI Timeline

# Study Assumptions

## *Base Case Descriptions:*

This study uses four base cases in various configurations:

- WECC 2015 Heavy Summer, with all NTTG Fast Track projects
- WECC 2015 Heavy Summer, with only MSTI
- WECC 2010 Light Autumn, with all NTTG Fast Track projects
- WECC 2010 Light Autumn, with only MSTI

These four base cases provide a broad range of scenarios for this study. Both heavy load and light load scenarios are studied with and without other NTTG Fast Track projects; these different scenarios help to meet regional WECC planning guidelines. They also help determine the impact that MSTI has on the existing system as well as the impact on any future projects. The NTTG projects include the following:

- Gateway South
- Gateway West
- Idaho to the Northwest (a.k.a., Hemingway – Boardman)
- Southwest Intertie Project ("SWIP")
- TransWest Express
- Hemmingway – Captain Jack

## *Expected Operating Conditions:*

The N-S proposed rating of 1500 MW was determined by using the 2015 Heavy Summer case. In order to achieve 1500 MW of flow on MSTI, generation was re-dispatched in Montana, Arizona, Utah, and California. Generation in Montana was increased by 1500 MW and decreased by 500 MW each in Arizona, Utah, and California. In order to achieve increased Montana exports, planned resources in NWE's queue were included in the base-cases. In the N-S rating cases, 1500 MW was shown to flow on MSTI with and without the other NTTG Fast Track projects.

When studying S-N flow, the 2010 Light Autumn base-case was used to determine the proposed rating of 950 MW. Generation was decreased in Montana and the northwest by 1000 MW, and increased by 1000 MW in Idaho and Wyoming. With the case dispatched as stated, the limiting element in this scenario was the angle range on the PST.

# Study Methodology/Guidelines

## *Study Methodology*

A study plan was developed and agreed to by the WECC Regional Planning Review Group. The plan can be summarized as follows:

1. Power-flow contingency analysis:
    a. The single element contingencies (i.e. N-1) listed in Appendix 3 were evaluated to screen for post-outage overloading of facilities and for unacceptable voltage performance to verify that WECC criteria were met for each outage.
    b. The double element contingencies (i.e. N-2), also listed in Appendix 3, were evaluated to screen for post outage overloading of facilities and for unacceptable voltage performance.
    c. A detailed study of the effects of MSTI on existing Remedial Action Schemes ("RAS") will be performed in the Phase 2 study.
2. Transient stability analysis:
    a. The transient stability of the system was evaluated with MSTI at its proposed power-flow rating. Light autumn and heavy summer cases were used in the study. In the comparison of results for cases with MSTI as a stand-alone project with cases that included the other NTTG Fast Track projects it was clear that adding the other NTTG projects served to improve the system performance.
    b. A detailed study of the effects of MSTI on existing Remedial Action Schemes ("RAS") will be performed in the Phase 2 study.
3. Reactive Margin Analysis:
    a. WECC requires that all new rated paths or facilities be tested for voltage stability at 2.5% over the proposed rating for all level C contingencies and at 5% over their proposed rating for all Level B contingencies to meet the WECC standard for voltage stability.

# Study Results and Conclusion

## *Planned Rating*

This study shows that the MSTI performance is acceptable at the proposed path rating of 1500 MW North to South, and 950 MW South to North for the non-simultaneous conditions studied. Some possible simultaneous impacts that will be studied in Phase 2 include:

- Path 8 (Montana to Northwest),
- Path 17 (Borah West),
- Path 18 (Montana-Idaho),
- Path 19 (Bridger West), and
- Path 20 (Path C).

## *Power-Flow Results*

In each base-case, flow on MSTI was increased until either 1500 MW was reached, or another limit was hit (i.e. available angle on phase shifting transformer). In both heavy summer cases, 1500 MW was achieved. In the light autumn cases, 1500 was reached with the addition of the NTTG Fast Track projects and a limit of approximately 1400 MW without the NTTG Fast Track projects. This limit of 1400 MW was because of a limitation of angle on the phase shifting transformer. After the transfer across MSTI was established, a series of post-transient contingencies were analyzed. A list of the N-1 and N-2 contingencies studied is provided in Appendix 3.

In all four cases, no thermal overloads were seen. A variety of voltage excursions were seen, but in all cases these excursions could be brought back to acceptable levels by using existing switched-shunt devices.

A summary of path flows for all four cases can be seen in the following table. Each column has a summary of values for the different base cases, including a summary of the northbound study

| | 2010LA N-S without Fast Track Projects | 2010LA N-S with Fast Track Projects | 2015HS N-S without Fast Track Projects | 2015HS N-S with Fast Track Projects | 2010LA S-N 950 MW |
|---|---|---|---|---|---|
| | | | | | |
| NORTHWEST AREA DATA | | | | | |
| TOTAL NW LOAD | 23785.5 | 23785.5 | 26305 | 26305 | 23785.5 |
| TOTAL NW LOSS | 763.9 | 771.1 | 1241 | 1172.4 | 880 |

## APPENDIX A-5-E

| | 2010LA N-S without Fast Track Projects | 2010LA N-S with Fast Track Projects | 2015HS N-S without Fast Track Projects | 2015HS N-S with Fast Track Projects | 2010LA S-N 950 MW |
|---|---|---|---|---|---|
| TOTAL NW INT | -6486.2 | -6486.1 | 3157.8 | 3157.7 | -7084.5 |
| TOTAL NW GEN | 18106.2 | 18113.6 | 30745.9 | 30677.6 | 17624.4 |
| | | | | | |
| **KEY NW PATH FLOWS** | | | | | |
| | | | | | |
| NORTH OF JOHN DAY FLOWS | -1552.8 | -1618 | 3219 | 3356.8 | -1607.8 |
| COI FLOWS | -2067.1 | -2081.3 | 4567.9 | 4520.2 | -3873.5 |
| PCDC FLOWS @CELILO1&2 | -739.2 | -739.2 | 800 | 800 | -739.2 |
| PCDC FLOWS @CELILO3&4 | -1108.1 | -1108.1 | 1200 | 1200 | -1108.1 |
| BC HYDRO-NORTHWEST FLOWS | -686.3 | -687.2 | 2613.2 | 2613.5 | -766.5 |
| | | | | | |
| **MONTANA** | | | | | |
| | | | | | |
| **MONTANA AREA DATA** | | | | | |
| | | | | | |
| TOTAL MONTANA LOAD | 1305.1 | 1305.1 | 1842.8 | 1842.8 | 1305.1 |
| TOTAL MONTANA LOSS | 270 | 267.4 | 282.2 | 278.1 | 167.6 |
| TOTAL MONTANA INT | 3328.6 | 3327.6 | 2805.9 | 2806.4 | 512.2 |
| TOTAL MONTANA GEN | 4904.2 | 4900.7 | 4931.7 | 4928.1 | 1941.2 |
| | | | | | |
| **MONTANA PATH FLOWS** | | | | | |
| | | | | | |
| MONTANA-NORTHWEST FLOW | 2053.2 | 1911.2 | 845.2 | 775 | 2168.9 |
| ALBERTA-BCHYDRO FLOW | 313.5 | 312.8 | -86.8 | -86.5 | 225.8 |
| GREAT FALLS SOUTH FLOW | 259.9 | 260.4 | 169.4 | 212 | -8.0 |
| MONTANA-ALBERTA FLOW | 313.3 | 312.9 | 313.2 | 313.5 | 225.8 |
| GREAT FALLS-HILINE FLOW | 21.8 | 21.8 | 32.7 | 32.2 | 21.8 |
| | | | | | |
| AMPS FLOW (230KV 250MW) | -75.7 | -89 | 160.9 | 150.3 | -198.4 |
| AMPS PST ANGLE | 0 | 0 | 0 | 0 | 0 |
| AMPS+JEFF FLOW (MTID337) | -152.1 | -171.1 | 233.7 | 217.2 | -331.7 |
| JEFFERSON PST ANGLE | 14 | 14 | 14 | 14 | 14 |
| JEFFERSON PST FLOW | -102.2 | -108.2 | 27.7 | 21.9 | -162.5 |
| MSTI LINE FLOWS AT TWN | 1340.2 | 1498.1 | 1510.4 | 1516.5 | 954 |
| | | | | | |
| BROADVIEW-TOWNSEND FLOW1 | 1537.6 | 1538.8 | 1325.4 | 1309.5 | 797.8 |
| BROADVIEW-TOWNSEND FLOW2 | 1537.6 | 1538.8 | 1325.4 | 1309.5 | 797.8 |
| BROADVIEW-JUDITHGAP FLOW | -108.8 | -110 | -76.2 | -76 | -125.4 |
| SHOREYROAD-WILSALL | -94.3 | -96.6 | -61.9 | -71.7 | -128.4 |

## APPENDIX A-5-E

| | 2010LA N-S without Fast Track Projects | 2010LA N-S with Fast Track Projects | 2015HS N-S without Fast Track Projects | 2015HS N-S with Fast Track Projects | 2010LA S-N 950 MW |
|---|---|---|---|---|---|
| FLOW | | | | | |
| BROADVIEW230/100 FLOW1 | -8.3 | -8.6 | -1.2 | -2.3 | -10.1 |
| BROADVIEW230/100 FLOW2 | -8.5 | -8.8 | -1.3 | -2.3 | -10.3 |
| COLUMB-RJ_WEST 161 KV | -34.7 | -35.8 | -25.3 | -31.5 | -50.3 |
| WEST OF BROADVIEW FLOW | 2820.6 | 2817.7 | 2485 | 2435.2 | 1271.2 |
| | | | | | |
| YELLOWTAIL NORTH FLOWS | 56.5 | 57.1 | -74.4 | -165.8 | 67.4 |
| YELLOWTAIL SOUTH FLOWS | 68.6 | 68 | 329.4 | 420.9 | 57.7 |
| MILES CITY DC TIE FLOW | 142 | 142 | 142 | 142 | 142 |
| YELLOWTAIL GENERATION | 130 | 130 | 260 | 260 | 130 |
| MONTANA-SOUTHEAST FLOWS | -185.6 | -186.2 | -47.5 | 44.4 | -196.5 |
| | | | | | |
| WEST OF COLSTRIP | 2668.9 | 2665.4 | 2632.5 | 2675.3 | 1075.9 |
| WEST OF CROSSOVER | 2827 | 2823.7 | 2674.9 | 2699.7 | 1233.4 |
| | | | | | |
| MONTANA PHASE-SHIFTERS | | | | | |
| | | | | | |
| RIMROCK PST ANGLE | -34 | -36.2 | 10 | 10 | -58.8 |
| RIMROCK PST FLOW | -34.5 | -34.6 | -21.5 | -3 | -34.5 |
| BILLINGS PST ANGLE | -35.5 | -37.7 | 10 | 10 | -60 |
| BILLINGS PST FLOW | -78.4 | -78.7 | -58 | -2.7 | -89.2 |
| CROSSOVER PST ANGLE | -39.5 | -41.8 | -1.5 | 0 | -66.3 |
| CROSSOVER PST FLOW | 57.1 | 56.9 | 156.1 | 173.9 | 57.1 |
| MSTI PST ANGLE | -60 | -60 | -26.79 | -38.69 | 60 |
| MATL PST ANGLE | 3.2 | 3.9 | 63.2 | 63.6 | -4.4 |
| MATL PST FLOW | -313 | -312.6 | -312.8 | -313.2 | -312.8 |
| | | | | | |
| | | | | | |
| **MONTANA GENERATORS** | | | | | |
| | | | | | |
| MONTANA THERMAL 1 | 330 | 330 | 330 | 330 | 0 |
| MONTANA THERMAL 2 | 330 | 330 | 330 | 330 | 330 |
| MONTANA THERMAL 3 | 805.2 | 801.7 | 807.7 | 803.4 | 367.2 |
| MONTANA THERMAL 4 | 805 | 805 | 805 | 805 | 0 |
| MONTANA THERMAL 1-4 total | 2270.2 | 2266.7 | 2272.7 | 2268.4 | 697.2 |
| MONTANA THERMAL 6 | 162 | 162 | 151 | 151 | 162 |
| MONTANA THERMAL 7 | 39 | 39 | 39 | 39 | 39 |
| MONTANA THERMAL 8 | 58 | 58 | 59 | 59 | 58 |
| MONTANA THERMAL 9 | 109 | 109 | 107 | 107 | 109 |
| MONTANA THERMAL 10 | 140 | 140 | 140 | 139 | 80 |
| MONTANA THERMAL 11 | 80 | 80 | 80 | 79 | 80 |
| MONTANA THERMAL 12 | 90 | 90 | 90 | 96 | 90 |

## APPENDIX A-5-E

| | 2010LA N-S without Fast Track Projects | 2010LA N-S with Fast Track Projects | 2015HS N-S without Fast Track Projects | 2015HS N-S with Fast Track Projects | 2010LA S-N 950 MW |
|---|---|---|---|---|---|
| MONTANA THERMAL 13 | 250 | 250 | 250 | 254 | 250 |
| MONTANA THERMAL 14 | 290 | 290 | 300 | 329 | 0 |
| MONTANA THERMAL 15 | 250 | 250 | 260 | 248 | 0 |
| MONTANA THERMAL 16 | 250 | 250 | 260 | 248 | 0 |
| MONTANA THERMAL 17 | 0 | 0 | 0 | 0 | 0 |
| MONTANA THERMAL 18 | 500 | 500 | 520 | 496 | 0 |
| TOTAL THERMAL GEN | 3738.2 | 3734.7 | 3708.7 | 3783.4 | 1315.2 |
| | | | | | |
| MONTANA WIND 1 | 135 | 135 | 135 | 135 | 135 |
| MONTANA WIND 2 | 340 | 340 | 370 | 363 | 0 |
| MONTANA WIND 3 | 110 | 110 | 100 | 10 | 0 |
| MONTANA WIND 4 | 45 | 45 | 40 | 48 | 45 |
| MONTANA WIND 5 | 90 | 90 | 90 | 95 | 0 |
| TOTAL WIND GEN | 720 | 720 | 735 | 651 | 180 |
| | | | | | |
| MONTANA HYDRO 1 | 140 | 140 | 151 | 151 | 140 |
| MONTANA HYDRO 2 | 65 | 65 | 68 | 68 | 65 |
| MONTANA HYDRO 1 & 2 TOTL | 205 | 205 | 219 | 219 | 205 |
| | | | | | |
| MONTANA HYDRO 3 | 12 | 12 | 13 | 13 | 12 |
| MONTANA HYDRO 4 | 40 | 40 | 41 | 41 | 40 |
| MONTANA HYDRO 5 | 30 | 30 | 50 | 50 | 30 |
| MONTANA HYDRO 6 | 4 | 4 | 4 | 4 | 4 |
| MONTANA HYDRO 7 | 14 | 14 | 15 | 15 | 14 |
| MONTANA HYDRO 8 | 46 | 46 | 49 | 49 | 46 |
| MONTANA HYDRO 9 | 42 | 42 | 43 | 43 | 42 |
| MONTANA HYDRO 10 | 38 | 38 | 39 | 39 | 38 |
| MONTANA HYDRO 11 | 6 | 6 | 6 | 6 | 6 |
| MONTANA HYDRO 3-11 TOTL | 232 | 232 | 260 | 260 | 232 |
| | | | | | |
| **IDAHO** | | | | | |
| | | | | | |
| **IDAHO AREA DATA** | | | | | |
| | | | | | |
| TOTAL IDAHO LOAD | 1784 | 1784 | 3771.3 | 3771.3 | 1784 |
| TOTAL IDAHO LOSS | 101.5 | 104 | 184.4 | 162 | 194.1 |
| TOTAL IDAHO INT | 643.2 | 642.7 | 406 | 405.9 | 2043.2 |
| TOTAL IDAHO GEN | 2528.8 | 2530.7 | 4361.8 | 4339.2 | 4021.4 |
| WYOMING WEST THERMAL 1 | 0 | 0 | 545 | 545 | 562 |
| WYOMING WEST THERMAL 2 | 560 | 560 | 545 | 545 | 562 |
| WYOMING WEST THERMAL 3 | 545 | 545 | 545 | 545 | 562 |
| WYOMING WEST THERMAL 4 | 545 | 545 | 545 | 545 | 562 |
| WYOMING WEST THERMAL | 1650 | 1650 | 2180 | 2180 | 2248 |

| | 2010LA N-S without Fast Track Projects | 2010LA N-S with Fast Track Projects | 2015HS N-S without Fast Track Projects | 2015HS N-S with Fast Track Projects | 2010LA S-N 950 MW |
|---|---|---|---|---|---|
| | | | | | |
| KEY IDAHO PATH FLOWS (MW) | | | | | |
| | | | | | |
| IDAHO-NORTHWEST FLOWS | 1329.3 | 1454.1 | 243.9 | 265.1 | 126.9 |
| MIDPOINT - SUMMER LAKE | 1015.2 | 1111.2 | 656.3 | 662.8 | -971.5 |
| BORAH WEST FLOWS | 441 | 421.3 | 227.7 | 323.2 | 638.2 |
| BRIDGER WEST FLOWS | 398.4 | 399 | 778.3 | 2327.6 | 507.3 |
| | | | | | |
| PACE AREA DATA | | | | | |
| | | | | | |
| TOTAL PACE LOAD | 6096.9 | 6096.9 | 10051.3 | 10051.3 | 6096.9 |
| TOTAL PACE LOSS | 240.4 | 240.2 | 344.5 | 296.7 | 240.7 |
| TOTAL PACE INT | -1398.4 | -1398.5 | -2523.2 | -2523.2 | -698.4 |
| TOTAL PACE GEN | 4943.8 | 4943.5 | 7879.5 | 7831.9 | 5644.1 |
| | | | | | |
| KEY PACE PATH FLOWS (MW) | | | | | |
| | | | | | |
| PATH C FLOWS | 68.7 | 61.7 | -390 | -65.6 | 157.1 |
| TOT2 FLOWS | -446.1 | -435.3 | 323.7 | 301.7 | 161.6 |
| TOT4A FLOWS | 559.2 | 556.7 | 429.8 | 316.5 | 432.5 |
| TOT4B FLOWS | 227.7 | 228.2 | 134.9 | 112.5 | 239.9 |

## *Transient Stability Results*

The transient stability study revealed no problems with MSTI inserted into the existing system.

A list of the outages simulated is summarized below:

| Fault Description | Line Segment Opened |
|---|---|
| 3-Phase Fault at Garrison 500 kV | Garrison -- Taft (both circuits) |
| 1-Phase Fault at Garrison 500 kV | Garrison -- Taft (single circuit) |
| 3-Phase Fault at Garrison 500 kV | Garrison -- Taft (single circuit) |
| 3-Phase Fault at Broadview 500 kV | Broadview -- Colstrip |
| 1-Phase Fault at Broadview 500 kV | Broadview -- Colstrip |
| 3-Phase Fault at Taft 500 kV | Taft – Bell |
| 3-Phase Fault at Taft 500 kV | Taft -- Dworshak |
| 3-Phase Fault at Townsend 500 kV | Townsend -- Midpoint (MSTI) |
| 3-Phase Fault at Midpoint 500 kV | Townsend -- Midpoint (MSTI) |

| | |
|---|---|
| 3-Phase Fault at Townsend 500 kV | Townsend -- Garrison (both circuits) |
| 3-Phase Fault at Townsend 500 kV | Townsend -- Garrison (single circuit) |
| 3-Phase Fault at Broadview 500 kV | Broadview -- Townsend (both circuits) |
| 3-Phase Fault at Broadview 500 kV | Broadview -- Townsend (single circuit) |
| 3-Phase Fault at Midpoint 500 kV | Midpoint -- Summer Lake |

The table of results can be found in Appendix 4. The system met all WECC criteria for the outages performed. NWE intends to fully study the simultaneous path dynamics in Phase 2, as well as perform a detailed study of the Jim Bridger system with appropriate RAS action.

## *Reactive Margin Results*

WECC requires that a path must be tested at a flow level 2.5% above the proposed rating for all level C contingencies, and at a flow level 5% over the proposed rating for Level B contingencies to test for voltage stability. For this analysis, N-S flow on MSTI was increased by 5% of its rating on a 2015 heavy summer case. A case summary can be found below:

| | |
|---|---|
| **NORTHWEST AREA DATA** | |
| | |
| TOTAL NW LOAD | 26305 |
| TOTAL NW LOSS | 1193.1 |
| TOTAL NW INT | 3157.6 |
| TOTAL NW GEN | 30698.1 |
| | |
| **KEY NW PATH FLOWS** | |
| | |
| NORTH OF JOHN DAY FLOWS | 3423.2 |
| COI FLOWS | 4528.3 |
| PCDC FLOWS @CELILO1&2 | 800 |
| PCDC FLOWS @CELILO3&4 | 1200 |
| BC HYDRO-NORTHWEST FLOWS | 2612.8 |
| | |
| **MONTANA** | |
| | |
| **MONTANA AREA DATA** | |
| | |
| TOTAL MONTANA LOAD | 1842.8 |
| TOTAL MONTANA LOSS | 359.2 |
| TOTAL MONTANA INT | 3006.5 |
| TOTAL MONTANA GEN | 5209.4 |
| | |
| MONTANA PATH FLOWS | |
| | |
| MONTANA-NORTHWEST FLOW | 927.1 |
| ALBERTA-BCHYDRO FLOW | -87.2 |
| GREAT FALLS SOUTH FLOW | 213.1 |
| MONTANA-ALBERTA FLOW | 312.8 |
| GREAT FALLS-HILINE FLOW | 31.9 |
| | |
| AMPS FLOW (230KV 250MW) | 157.6 |
| AMPS PST ANGLE | 0 |
| AMPS+JEFF FLOW (MTID337) | 229.5 |
| JEFFERSON PST ANGLE | 14 |
| JEFFERSON PST FLOW | 26.9 |
| MSTI LINE FLOWS AT TWN | 1579.4 |
| | |

## APPENDIX A-5-E

| | |
|---|---|
| BROADVIEW-TOWNSEND FLOW1 | 1425.2 |
| BROADVIEW-TOWNSEND FLOW2 | 1425.2 |
| BROADVIEW-JUDITHGAP FLOW | -72.2 |
| SHOREYROAD-WILSALL FLOW | -68 |
| BROADVIEW230/100 FLOW1 | -1.9 |
| BROADVIEW230/100 FLOW2 | -1.9 |
| COLUMB-RJ_WEST 161 KV | -30.2 |
| WEST OF BROADVIEW FLOW | 2676.1 |
| | |
| YELLOWTAIL NORTH FLOWS | -197.6 |
| YELLOWTAIL SOUTH FLOWS | 452.6 |
| MILES CITY DC TIE FLOW | 142 |
| YELLOWTAIL GENERATION | 260 |
| MONTANA-SOUTHEAST FLOWS | 76.5 |
| | |
| WEST OF COLSTRIP | 2956.5 |
| WEST OF CROSSOVER | 2969.4 |
| | |
| **MONTANA PHASE-SHIFTERS** | |
| | |
| RIMROCK PST ANGLE | 10 |
| RIMROCK PST FLOW | 2 |
| BILLINGS PST ANGLE | 10 |
| BILLINGS PST FLOW | 13.1 |
| CROSSOVER PST ANGLE | 0 |
| CROSSOVER PST FLOW | 185.2 |
| MSTI PST ANGLE | -60 |
| MILL CREEK PST FLOW | -269.2 |
| MATL PST ANGLE | 62.4 |
| MATL PST FLOW | -312.5 |
| | |
| **MONTANA GENERATORS** | |
| | |
| MONTANA THERMAL 1 | 330 |
| MONTANA THERMAL 2 | 330 |
| MONTANA THERMAL 3 | 803.5 |
| MONTANA THERMAL 4 | 805 |
| MONTANA THERMAL 1-4 Total | 2268.5 |
| MONTANA THERMAL 6 | 200 |
| MONTANA THERMAL 7 | 39 |
| MONTANA THERMAL 8 | 59 |
| MONTANA THERMAL 9 | 200 |
| MONTANA THERMAL 10 | 139 |
| MONTANA THERMAL 11 | 79 |
| MONTANA THERMAL 12 | 96 |
| MONTANA THERMAL 13 | 254 |
| MONTANA THERMAL 14 | 329 |

## APPENDIX A-5-E

| | |
|---|---|
| MONTANA THERMAL 15 | 248 |
| MONTANA THERMAL 16 | 248 |
| MONTANA THERMAL 17 | 0 |
| MONTANA THERMAL 18 | 496 |
| TOTAL THERMAL GEN | 4064.6 |
| | |
| MONTANA WIND 1 | 135 |
| MONTANA WIND 2 | 363 |
| MONTANA WIND 3 | 10 |
| MONTANA WIND 4 | 48 |
| MONTANA WIND 5 | 95 |
| TOTAL WIND GEN | 651 |
| | |
| MONTANA HYDRO 1 | 151 |
| MONTANA HYDRO 2 | 68 |
| MONTANA HYDRO 1 & 2 TOTL | 219 |
| | |
| MONTANA HYDRO 3 | 13 |
| MONTANA HYDRO 4 | 41 |
| MONTANA HYDRO 5 | 50 |
| MONTANA HYDRO 6 | 4 |
| MONTANA HYDRO 7 | 15 |
| MONTANA HYDRO 8 | 49 |
| MONTANA HYDRO 9 | 43 |
| MONTANA HYDRO 10 | 39 |
| MONTANA HYDRO 11 | 6 |
| MONTANA HYDRO 3-11 TOTL | 260 |
| | |
| **IDAHO** | |
| | |
| **IDAHO AREA DATA** | |
| | |
| TOTAL IDAHO LOAD | 3771.3 |
| TOTAL IDAHO LOSS | 164.5 |
| TOTAL IDAHO INT | 305.8 |
| TOTAL IDAHO GEN | 4241.6 |
| WYOMING WEST THERMAL 1 | 545 |
| WYOMING WEST THERMAL 2 | 545 |
| WYOMING WEST THERMAL 3 | 545 |
| WYOMING WEST THERMAL 4 | 545 |
| WYOMING WEST THERMAL TTL | 2180 |
| | |
| **KEY IDAHO PATH FLOWS (MW)** | |
| | |
| IDAHO-NORTHWEST FLOWS | 121.8 |
| MIDPOINT - SUMMER LAKE | 628.5 |
| BORAH WEST FLOWS | 272.3 |

| | |
|---|---|
| BRIDGER WEST FLOWS | 2307.9 |
| | |
| **PACE AREA DATA** | |
| | |
| TOTAL PACE LOAD | 10051.3 |
| TOTAL PACE LOSS | 301.8 |
| TOTAL PACE INT | -2623.2 |
| TOTAL PACE GEN | 7737 |
| | |
| **KEY PACE PATH FLOWS (MW)** | |
| | |
| PATH C FLOWS | -75.4 |
| TOT2 FLOWS | 293 |
| TOT4A FLOWS | 333.9 |
| TOT4B FLOWS | 96.8 |

The same N-1 and N-2 contingencies studied for the power flow analysis were run on the case with increased power flow on MSTI. This study did not reveal any thermal overloads or voltage collapse problems.

## *Conclusion*

NWE has proposed a planned north to south ("N-S") rating of 1500 MW on MSTI. Power-flow and angle stability studies show that a 1500 MW N-S rating is reasonable and achievable on the MSTI line. Studies also show that a south to north ("S-N") planned rating of 950 MW for MSTI is reasonable and achievable. This study shows that these ratings can be achieved with no adverse effects on the existing system and in full compliance with NERC and WECC Standards.

NorthWestern Energy believes it conforms to the guidelines in the WECC Path Rating Process. With this report, NorthWestern Energy expects to conclude Phase 1 of the path rating process.

## APPENDIX A-5-E

# Appendix 1: Contact Information

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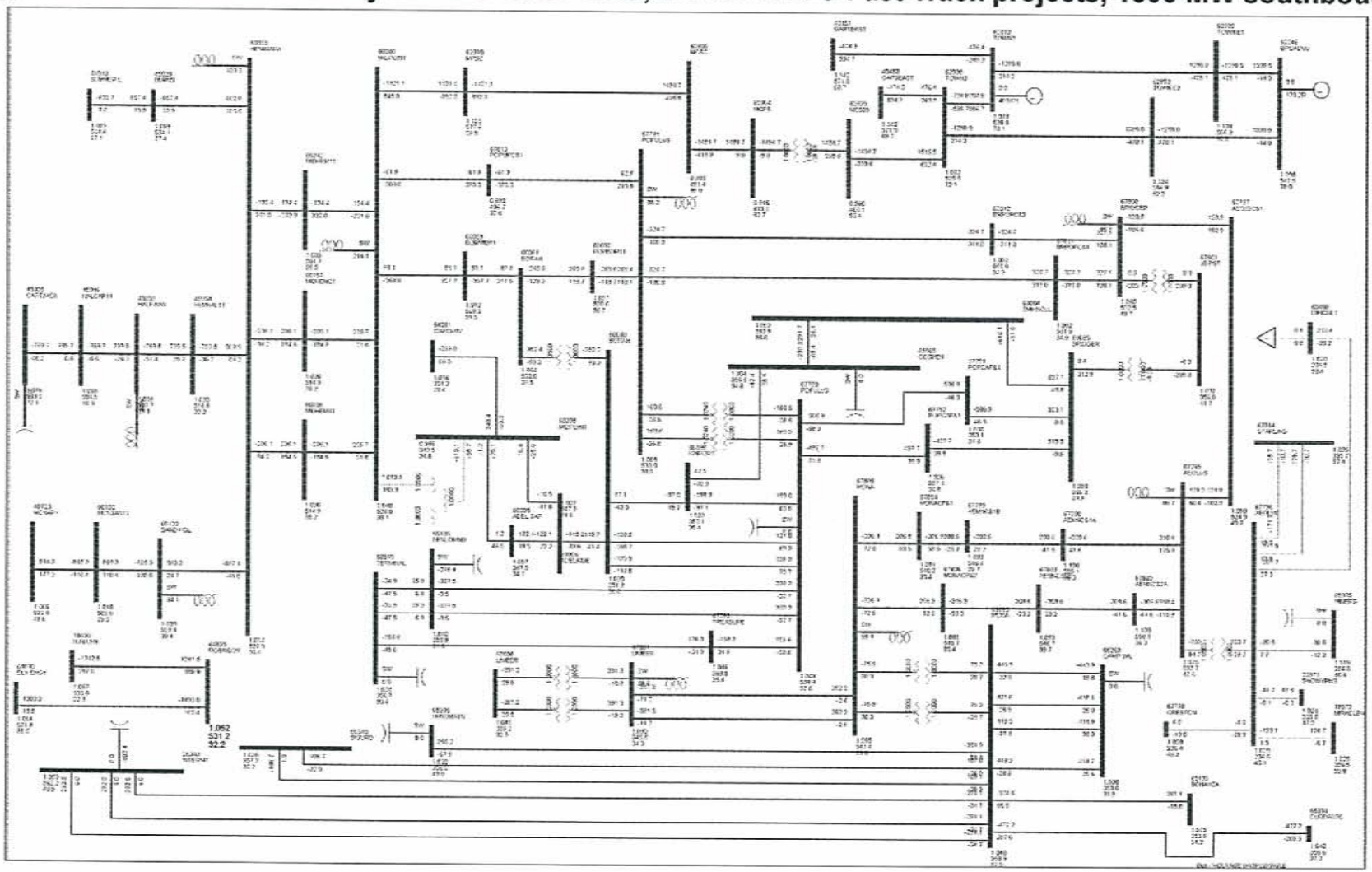
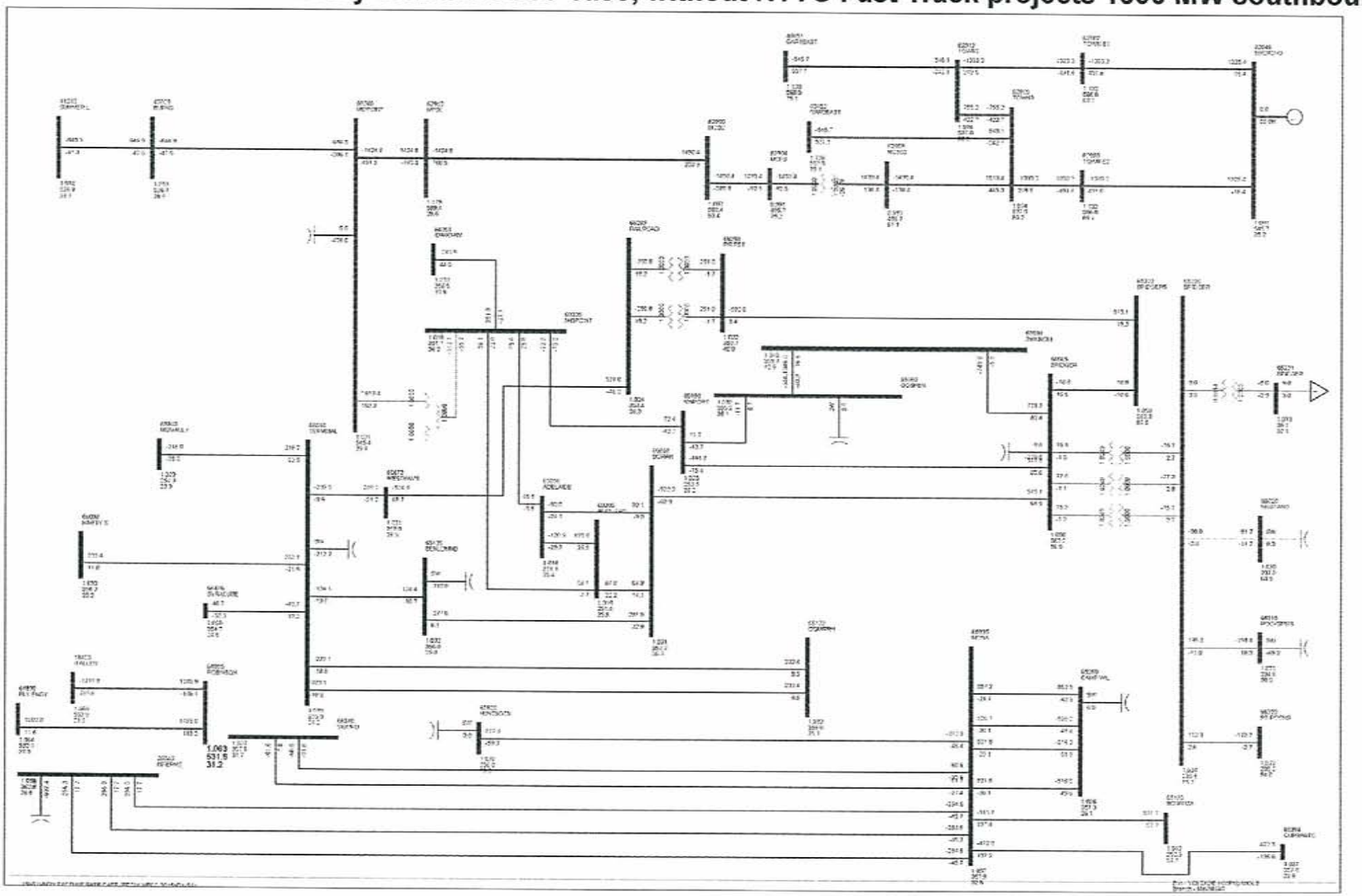
APPENDIX A-5-E

## Appendix 2: WECC 2015 heavy summer base-case, with all NTTG Fast Track projects, 1500 MW southbound



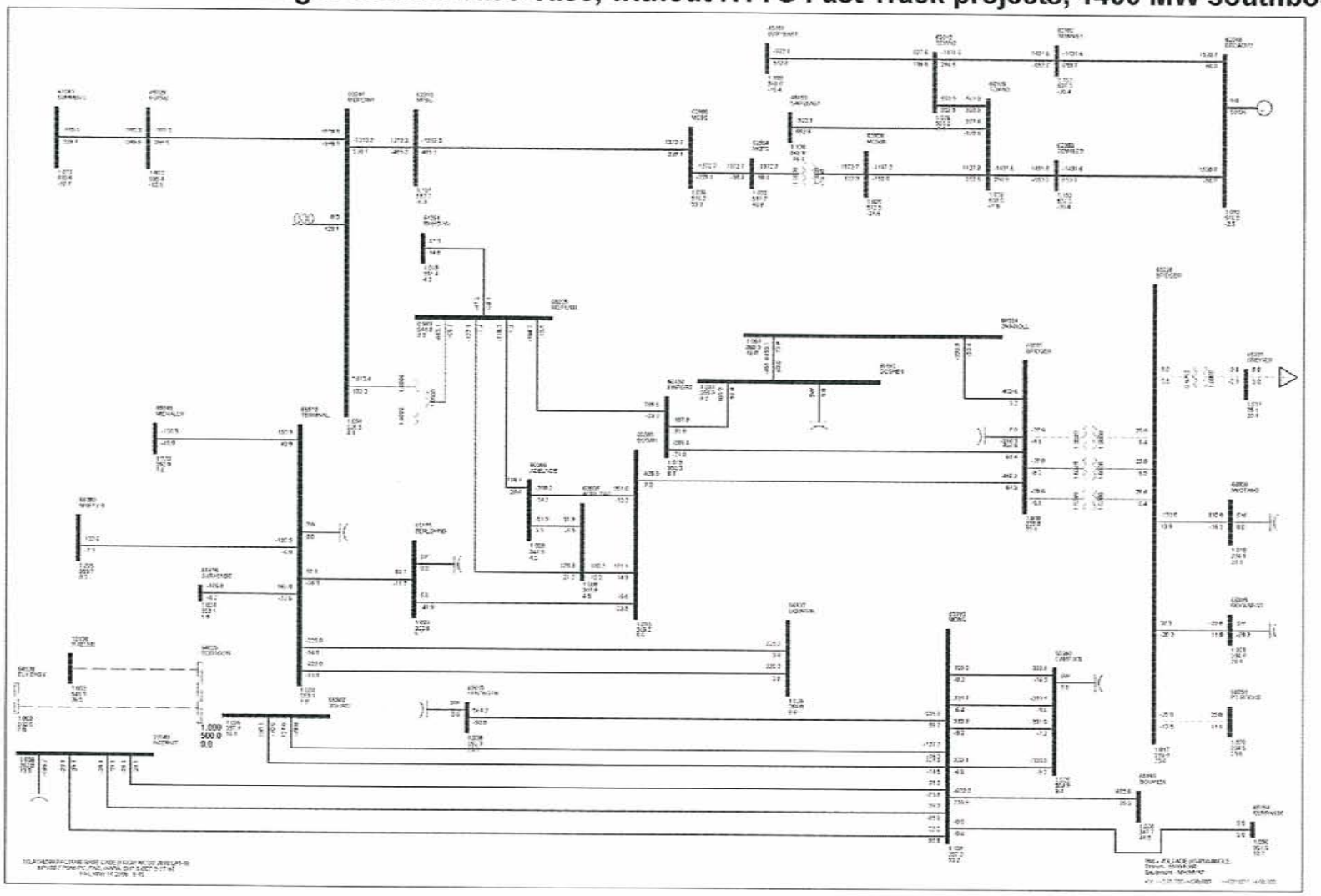
APPENDIX A-5-E

## Appendix 2: WECC 2015 heavy summer base-case, without NTTG Fast Track projects 1500 MW southbound



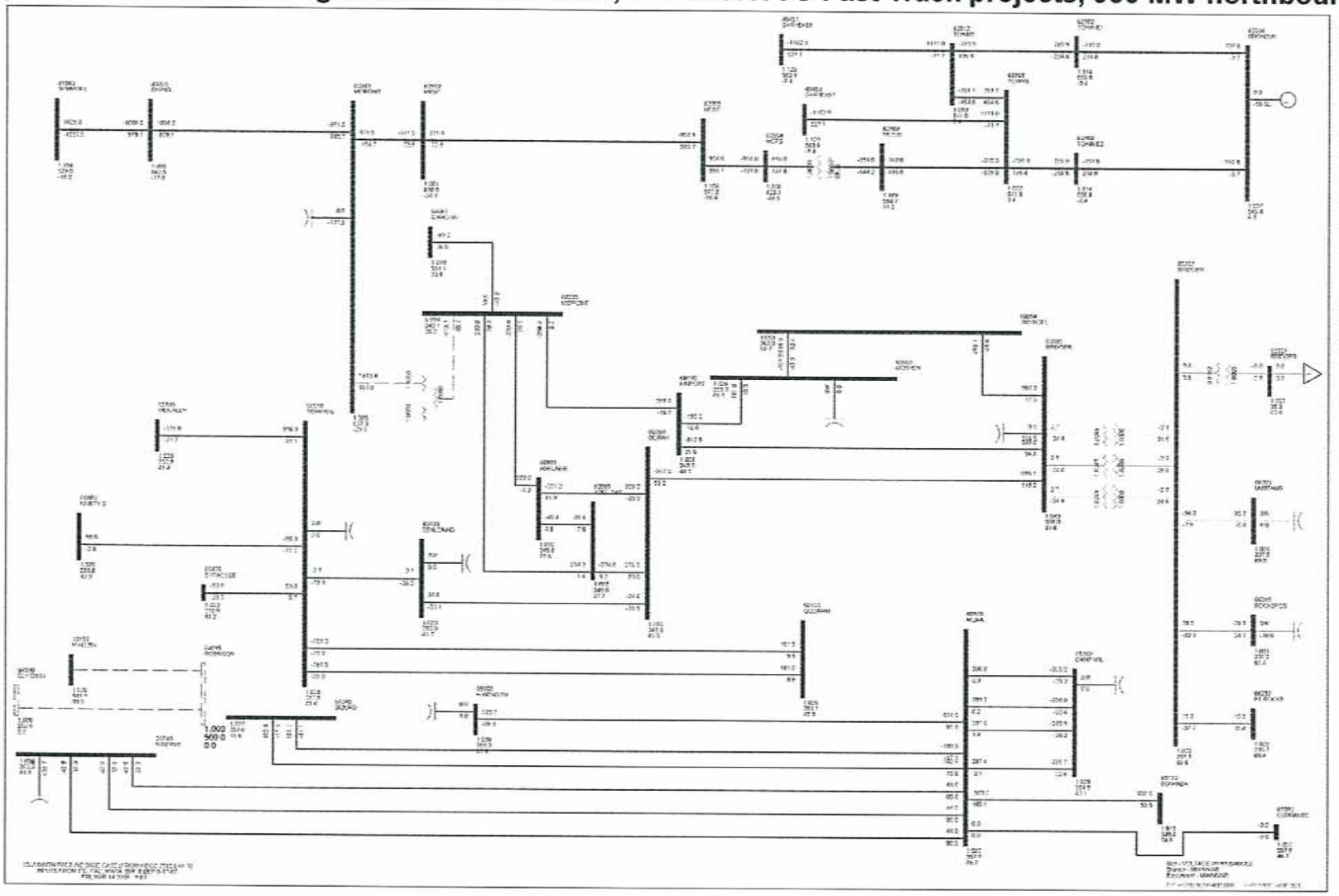
APPENDIX A-5-E

## Appendix 2: WECC 2010 light autumn base-case, without NTTG Fast Track projects, 1400 MW southbound



**APPENDIX A-5-E**

## Appendix 2: WECC 2010 light autumn base-case, without NTTG Fast Track projects, 950 MW northbound.



APPENDIX A-5-E

# Appendix 3: Power Flow Contingency List

## *N-1 Contingency List:*

```
SINGLE 1    : OPEN LINE FROM BUS 60005 [ADEL TAP    345.00] TO BUS 60006 [ADELAIDE    345.00] CKT 1
SINGLE 2    : OPEN LINE FROM BUS 60005 [ADEL TAP    345.00] TO BUS 60060 [BORAH       345.00] CKT 1
SINGLE 3    : OPEN LINE FROM BUS 60005 [ADEL TAP    345.00] TO BUS 60235 [MIDPOINT    345.00] CKT 1
SINGLE 4    : OPEN LINE FROM BUS 60006 [ADELAIDE    345.00] TO BUS 60060 [BORAH       345.00] CKT 2
SINGLE 5    : OPEN LINE FROM BUS 60006 [ADELAIDE    345.00] TO BUS 60235 [MIDPOINT    345.00] CKT 2
SINGLE 6    : OPEN LINE FROM BUS 60045 [BOISEBCH    230.00] TO BUS 60095 [BROWNLEE    230.00] CKT &2
SINGLE 7    : OPEN LINE FROM BUS 60045 [BOISEBCH    230.00] TO BUS 60095 [BROWNLEE    230.00] CKT &3
SINGLE 8    : OPEN LINE FROM BUS 60045 [BOISEBCH    230.00] TO BUS 60102 [HORSEFLT    230.00] CKT &4
SINGLE 9    : OPEN LINE FROM BUS 60045 [BOISEBCH    230.00] TO BUS 60130 [DRAM        230.00] CKT 1
SINGLE 10   : OPEN LINE FROM BUS 60045 [BOISEBCH    230.00] TO BUS 60207 [LOCUST      230.00] CKT 1
SINGLE 11   : OPEN LINE FROM BUS 60045 [BOISEBCH    230.00] TO BUS 60232 [MIDPOINT    230.00] CKT &3
SINGLE 12   : OPEN LINE FROM BUS 60045 [BOISEBCH    230.00] TO BUS 60249 [HUBBARD     230.00] CKT 1
SINGLE 13   : OPEN LINE FROM BUS 60045 [BOISEBCH    230.00] TO BUS 60395 [RTLSNAKE    230.00] CKT 2
SINGLE 14   : OPEN LINE FROM BUS 60045 [BOISEBCH    230.00] TO BUS 60420 [PEARL_ID    230.00] CKT &1
SINGLE 15   : OPEN LINE FROM BUS 60060 [BORAH       345.00] TO BUS 60062 [BORAH       230.00] CKT 1
SINGLE 16   : OPEN LINE FROM BUS 60060 [BORAH       345.00] TO BUS 60085 [BRIDGER     345.00] CKT &1
SINGLE 17   : OPEN LINE FROM BUS 60060 [BORAH       345.00] TO BUS 65135 [BENLOMND    345.00] CKT 1
SINGLE 18   : OPEN LINE FROM BUS 60062 [BORAH       230.00] TO BUS 60073 [BRADY       230.00] CKT 1
SINGLE 19   : OPEN LINE FROM BUS 60062 [BORAH       230.00] TO BUS 60073 [BRADY       230.00] CKT 2
SINGLE 20   : OPEN LINE FROM BUS 60062 [BORAH       230.00] TO BUS 60165 [HUNT        230.00] CKT 1
SINGLE 21   : OPEN LINE FROM BUS 60073 [BRADY       230.00] TO BUS 60185 [KINPORT     230.00] CKT 1
SINGLE 22   : OPEN LINE FROM BUS 60073 [BRADY       230.00] TO BUS 60185 [KINPORT     230.00] CKT 2
SINGLE 23   : OPEN LINE FROM BUS 60073 [BRADY       230.00] TO BUS 65075 [ANTLOPE     230.00] CKT 1
SINGLE 24   : OPEN LINE FROM BUS 60073 [BRADY       230.00] TO BUS 66565 [TREASTON    230.00] CKT 1
SINGLE 25   : OPEN LINE FROM BUS 60084 [3MIKNOLL    345.00] TO BUS 60085 [BRIDGER     345.00] CKT &1
SINGLE 26   : OPEN LINE FROM BUS 60084 [3MIKNOLL    345.00] TO BUS 60092 [BRIDGE&B    345.00] CKT 1
SINGLE 27   : OPEN LINE FROM BUS 60084 [3MIKNOLL    345.00] TO BUS 65665 [GOSHEN      345.00] CKT 1
SINGLE 28   : OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 60092 [BRIDGE&B    345.00] CKT 1
SINGLE 29   : OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 60190 [KINPORT     345.00] CKT &1
SINGLE 30   : OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 65220 [BRIDGER     230.00] CKT 1
SINGLE 31   : OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 65220 [BRIDGER     230.00] CKT 2
SINGLE 32   : OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 65220 [BRIDGER     230.00] CKT 3
SINGLE 33   : OPEN LINE FROM BUS 60095 [BROWNLEE    230.00] TO BUS 60102 [HORSEFLT    230.00] CKT 4
SINGLE 34   : OPEN LINE FROM BUS 60095 [BROWNLEE    230.00] TO BUS 60150 [HELLSCYN    230.00] CKT 1
SINGLE 35   : OPEN LINE FROM BUS 60095 [BROWNLEE    230.00] TO BUS 60265 [ONTARIO     230.00] CKT &1
SINGLE 36   : OPEN LINE FROM BUS 60095 [BROWNLEE    230.00] TO BUS 60275 [OXBOW       230.00] CKT 1
SINGLE 37   : OPEN LINE FROM BUS 60095 [BROWNLEE    230.00] TO BUS 60275 [OXBOW       230.00] CKT 2
SINGLE 38   : OPEN LINE FROM BUS 60095 [BROWNLEE    230.00] TO BUS 60310 [QUARTZTP    230.00] CKT 1
SINGLE 39   : OPEN LINE FROM BUS 60095 [BROWNLEE    230.00] TO BUS 60420 [PEARL_ID    230.00] CKT &1
SINGLE 40   : OPEN LINE FROM BUS 60110 [CALDWELL    230.00] TO BUS 60265 [ONTARIO     230.00] CKT 1
SINGLE 41   : OPEN LINE FROM BUS 60110 [CALDWELL    230.00] TO BUS 60400 [GARNET      230.00] CKT 1
SINGLE 42   : OPEN LINE FROM BUS 60110 [CALDWELL    230.00] TO BUS 61828 [NAMPA TP    230.00] CKT 1
SINGLE 43   : OPEN LINE FROM BUS 60130 [DRAM        230.00] TO BUS 60232 [MIDPOINT    230.00] CKT 1
SINGLE 44   : OPEN LINE FROM BUS 60165 [HUNT        230.00] TO BUS 60232 [MIDPOINT    230.00] CKT 1
SINGLE 45   : OPEN LINE FROM BUS 60190 [KINPORT     345.00] TO BUS 60235 [MIDPOINT    345.00] CKT 1
SINGLE 46   : OPEN LINE FROM BUS 60190 [KINPORT     345.00] TO BUS 65665 [GOSHEN      345.00] CKT 1
SINGLE 47   : OPEN LINE FROM BUS 60207 [LOCUST      230.00] TO BUS 60400 [GARNET      230.00] CKT 1
SINGLE 48   : OPEN LINE FROM BUS 60207 [LOCUST      230.00] TO BUS 60420 [PEARL_ID    230.00] CKT 1
SINGLE 49   : OPEN LINE FROM BUS 60232 [MIDPOINT    230.00] TO BUS 60235 [MIDPOINT    345.00] CKT 1
SINGLE 50   : OPEN LINE FROM BUS 60232 [MIDPOINT    230.00] TO BUS 60235 [MIDPOINT    345.00] CKT 2
SINGLE 51   : OPEN LINE FROM BUS 60232 [MIDPOINT    230.00] TO BUS 60395 [RTLSNAKE    230.00] CKT &2
SINGLE 52   : OPEN LINE FROM BUS 60240 [MIDPOINT    500.00] TO BUS 62910 [MPSC        500.00] CKT 1
SINGLE 53   : OPEN LINE FROM BUS 60249 [HUBBARD     230.00] TO BUS 60256 [HAPPYVLY    230.00] CKT &1
SINGLE 54   : OPEN LINE FROM BUS 60249 [HUBBARD     230.00] TO BUS 60394 [DANSKIN     230.00] CKT 1
SINGLE 55   : OPEN LINE FROM BUS 60256 [HAPPYVLY    230.00] TO BUS 61828 [NAMPA TP    230.00] CKT &1
SINGLE 56   : OPEN LINE FROM BUS 60275 [OXBOW       230.00] TO BUS 60278 [IMNAHA      230.00] CKT &1
SINGLE 57   : OPEN LINE FROM BUS 60306 [QUARTZ      230.00] TO BUS 60310 [QUARTZTP    230.00] CKT 1
SINGLE 58   : OPEN LINE FROM BUS 60394 [DANSKIN     230.00] TO BUS 60396 [BNET MTN    230.00] CKT 1
SINGLE 59   : OPEN LINE FROM BUS 60395 [RTLSNAKE    230.00] TO BUS 60396 [BNET MTN    230.00] CKT 1
SINGLE 60   : OPEN LINE FROM BUS 61828 [NAMPA TP    230.00] TO BUS 61829 [NAMPA       230.00] CKT 1
SINGLE 61   : OPEN LINE FROM BUS 62004 [MILL CRK    230.00] TO BUS 62030 [PTRSNFLT    230.00] CKT 1
```

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SINGLE 62   : OPEN LINE FROM BUS 62004 [MILL CRK    230.00] TO BUS 62331 [THRRIVER    230.00] CKT 1
SINGLE 63   : OPEN LINE FROM BUS 62004 [MILL CRK    230.00] TO BUS 62339 [ANA BPA     230.00] CKT 1
SINGLE 64   : OPEN LINE FROM BUS 62004 [MILL CRK    230.00] TO BUS 62355 [MLCK PHA    230.00] CKT 1
SINGLE 65   : OPEN LINE FROM BUS 62004 [MILL CRK    230.00] TO BUS 62909 [MC500       500.00] CKT 1
SINGLE 66   : OPEN LINE FROM BUS 62012 [TOWN2       500.00] TO BUS 62902 [TOWN E1     500.00] CKT 1
SINGLE 67   : OPEN LINE FROM BUS 62012 [TOWN2       500.00] TO BUS 62908 [TOWN3       500.00] CKT 1
SINGLE 68   : OPEN LINE FROM BUS 62019 [WILSALL     230.00] TO BUS 62331 [THRRIVER    230.00] CKT 1
SINGLE 69   : OPEN LINE FROM BUS 62019 [WILSALL     230.00] TO BUS 62378 [WKN         230.00] CKT 1
SINGLE 70   : OPEN LINE FROM BUS 62026 [SHELBY      230.00] TO BUS 62035 [CNRDWAPA    230.00] CKT 1
SINGLE 71   : OPEN LINE FROM BUS 62030 [PTRSNFLT    230.00] TO BUS 62355 [MLCK PHA    230.00] CKT 1
SINGLE 72   : OPEN LINE FROM BUS 62030 [PTRSNFLT    230.00] TO BUS 65025 [AMPS        230.00] CKT 1
SINGLE 73   : OPEN LINE FROM BUS 62034 [BOLE        230.00] TO BUS 62035 [CNRDWAPA    230.00] CKT 1
SINGLE 74   : OPEN LINE FROM BUS 62034 [BOLE        230.00] TO BUS 62071 [GT FALLS    230.00] CKT 1
SINGLE 75   : OPEN LINE FROM BUS 62036 [JUDITHGP    230.00] TO BUS 62083 [JUDITHSO    230.00] CKT 1
SINGLE 76   : OPEN LINE FROM BUS 62036 [JUDITHGP    230.00] TO BUS 62502 [STH_TAP     230.00] CKT 1
SINGLE 77   : OPEN LINE FROM BUS 62045 [BLGS PHA    230.00] TO BUS 62082 [BILINGS     230.00] CKT 1
SINGLE 78   : OPEN LINE FROM BUS 62045 [BLGS PHA    230.00] TO BUS 66750 [YELOWTLP    230.00] CKT 1
SINGLE 79   : OPEN LINE FROM BUS 62046 [BROADVU     500.00] TO BUS 62053 [BROADV&2    500.00] CKT 2
SINGLE 80   : OPEN LINE FROM BUS 62046 [BROADVU     500.00] TO BUS 62054 [BROADV&1    500.00] CKT 1
SINGLE 81   : OPEN LINE FROM BUS 62046 [BROADVU     500.00] TO BUS 62902 [TOWN E1     500.00] CKT 1
SINGLE 82   : OPEN LINE FROM BUS 62046 [BROADVU     500.00] TO BUS 62903 [TOWN E2     500.00] CKT 2
SINGLE 83   : OPEN LINE FROM BUS 62051 [HARDIN      230.00] TO BUS 62060 [COLSTRP     230.00] CKT 1
SINGLE 84   : OPEN LINE FROM BUS 62052 [ALKALI      230.00] TO BUS 62058 [SHOREYRD    230.00] CKT 1
SINGLE 85   : OPEN LINE FROM BUS 62052 [ALKALI      230.00] TO BUS 62082 [BILINGS     230.00] CKT 1
SINGLE 86   : OPEN LINE FROM BUS 62052 [ALKALI      230.00] TO BUS 62223 [BROADVU     230.00] CKT 1
SINGLE 87   : OPEN LINE FROM BUS 62053 [BROADV&2    500.00] TO BUS 62057 [COLSTRP     500.00] CKT 2
SINGLE 88   : OPEN LINE FROM BUS 62054 [BROADV&1    500.00] TO BUS 62057 [COLSTRP     500.00] CKT 1
SINGLE 89   : OPEN LINE FROM BUS 62055 [BASELINE    230.00] TO BUS 62058 [SHOREYRD    230.00] CKT 1
SINGLE 90   : OPEN LINE FROM BUS 62056 [HUNTLEY     230.00] TO BUS 62082 [BILINGS     230.00] CKT 1
SINGLE 91   : OPEN LINE FROM BUS 62058 [SHOREYRD    230.00] TO BUS 62378 [WKN         230.00] CKT 1
SINGLE 92   : OPEN LINE FROM BUS 62060 [COLSTRP     230.00] TO BUS 62821 [LIGNITE     230.00] CKT 1
SINGLE 93   : OPEN LINE FROM BUS 62060 [COLSTRP     230.00] TO BUS 62821 [LIGNITE     230.00] CKT 2
SINGLE 94   : OPEN LINE FROM BUS 62071 [GT FALLS    230.00] TO BUS 62072 [OVANDO      230.00] CKT 1
SINGLE 95   : OPEN LINE FROM BUS 62071 [GT FALLS    230.00] TO BUS 62126 [LANDRSFK    230.00] CKT 1
SINGLE 96   : OPEN LINE FROM BUS 62071 [GT FALLS    230.00] TO BUS 62364 [MATLN_&2    230.00] CKT 1
SINGLE 97   : OPEN LINE FROM BUS 62071 [GT FALLS    230.00] TO BUS 62500 [SOUTHERN    230.00] CKT 1
SINGLE 98   : OPEN LINE FROM BUS 62071 [GT FALLS    230.00] TO BUS 62502 [STH_TAP     230.00] CKT 1
SINGLE 99   : OPEN LINE FROM BUS 62071 [GT FALLS    230.00] TO BUS 62574 [MNTGMRY     230.00] CKT 1
SINGLE 100  : OPEN LINE FROM BUS 62071 [GT FALLS    230.00] TO BUS 62921 [EHELENA     230.00] CKT 1
SINGLE 101  : OPEN LINE FROM BUS 62072 [OVANDO      230.00] TO BUS 62126 [LANDRSFK    230.00] CKT 1
SINGLE 102  : OPEN LINE FROM BUS 62072 [OVANDO      230.00] TO BUS 62344 [PLACIDLK    230.00] CKT 1
SINGLE 103  : OPEN LINE FROM BUS 62082 [BILINGS     230.00] TO BUS 62125 [BILINGSW    230.00] CKT 1
SINGLE 104  : OPEN LINE FROM BUS 62083 [JUDITHSO    230.00] TO BUS 62223 [BROADVU     230.00] CKT 1
SINGLE 105  : OPEN LINE FROM BUS 62125 [BILINGSW    230.00] TO BUS 62223 [BROADVU     230.00] CKT 1
SINGLE 106  : OPEN LINE FROM BUS 62331 [THRRIVER    230.00] TO BUS 62921 [EHELENA     230.00] CKT 1
SINGLE 107  : OPEN LINE FROM BUS 62362 [MARIAS      230.00] TO BUS 62363 [MATLN_&1    230.00] CKT 1
SINGLE 108  : OPEN LINE FROM BUS 62362 [MARIAS      230.00] TO BUS 62364 [MATLN_&2    230.00] CKT 1
SINGLE 109  : OPEN LINE FROM BUS 62500 [SOUTHERN    230.00] TO BUS 62502 [STH_TAP     230.00] CKT 1
SINGLE 110  : OPEN LINE FROM BUS 62903 [TOWN E2     500.00] TO BUS 62908 [TOWN3       500.00] CKT 2
SINGLE 113  : OPEN LINE FROM BUS 62905 [MCSC        500.00] TO BUS 62910 [MPSC        500.00] CKT 1
SINGLE 114  : OPEN LINE FROM BUS 62908 [TOWN3       500.00] TO BUS 62909 [MC500       500.00] CKT 1
SINGLE 115  : OPEN LINE FROM BUS 65025 [AMPS        230.00] TO BUS 65075 [ANTLOPE     230.00] CKT 1
SINGLE 116  : OPEN LINE FROM BUS 65060 [ANT MINE    230.00] TO BUS 66745 [YELLOWCK    230.00] CKT 1
SINGLE 117  : OPEN LINE FROM BUS 65075 [ANTLOPE     230.00] TO BUS 65910 [LOST RIV    230.00] CKT 1
SINGLE 118  : OPEN LINE FROM BUS 65090 [ATLANTIC    230.00] TO BUS 66740 [WYOPO       230.00] CKT 1
SINGLE 119  : OPEN LINE FROM BUS 65090 [ATLANTIC    230.00] TO BUS 67553 [WIND RIV    230.00] CKT 1
SINGLE 120  : OPEN LINE FROM BUS 65095 [BADWATER    230.00] TO BUS 66410 [SPENCE      230.00] CKT 1
SINGLE 121  : OPEN LINE FROM BUS 65095 [BADWATER    230.00] TO BUS 66535 [THERMOPL    230.00] CKT 1
SINGLE 122  : OPEN LINE FROM BUS 65105 [BAR-X       230.00] TO BUS 67529 [BITTERCK    230.00] CKT 2
SINGLE 123  : OPEN LINE FROM BUS 65105 [BAR-X       230.00] TO BUS 67770 [CRESTON     230.00] CKT 1
SINGLE 124  : OPEN LINE FROM BUS 65135 [BENLOMND    345.00] TO BUS 65140 [BENLOMND    230.00] CKT 1
SINGLE 125  : OPEN LINE FROM BUS 65135 [BENLOMND    345.00] TO BUS 66476 [SYRACUSE    345.00] CKT 1
SINGLE 126  : OPEN LINE FROM BUS 65135 [BENLOMND    345.00] TO BUS 66510 [TERMINAL    345.00] CKT 1
SINGLE 127  : OPEN LINE FROM BUS 65140 [BENLOMND    230.00] TO BUS 65160 [BIRCH CK    230.00] CKT 1
SINGLE 128  : OPEN LINE FROM BUS 65140 [BENLOMND    230.00] TO BUS 66050 [NAUGHTON    230.00] CKT 1
SINGLE 129  : OPEN LINE FROM BUS 65140 [BENLOMND    230.00] TO BUS 66515 [TERMINAL    230.00] CKT 1
SINGLE 130  : OPEN LINE FROM BUS 65160 [BIRCH CK    230.00] TO BUS 66050 [NAUGHTON    230.00] CKT 1
SINGLE 131  : OPEN LINE FROM BUS 65160 [BIRCH CK    230.00] TO BUS 66270 [RAILROAD    230.00] CKT 1
SINGLE 132  : OPEN LINE FROM BUS 65165 [BLACKSFK    230.00] TO BUS 66010 [MONUMENT    230.00] CKT 1
SINGLE 133  : OPEN LINE FROM BUS 65165 [BLACKSFK    230.00] TO BUS 66670 [WESTVACO    230.00] CKT 1
SINGLE 134  : OPEN LINE FROM BUS 65175 [BLUE RIM    230.00] TO BUS 65215 [MANSFACE    230.00] CKT 1
SINGLE 135  : OPEN LINE FROM BUS 65175 [BLUE RIM    230.00] TO BUS 66325 [SO TRONA    230.00] CKT 1
SINGLE 136  : OPEN LINE FROM BUS 65193 [BONANZA     345.00] TO BUS 65995 [MONA        345.00] CKT 1
SINGLE 137  : OPEN LINE FROM BUS 65215 [MANSFACE    230.00] TO BUS 65555 [FIREHOLE    230.00] CKT 1
SINGLE 138  : OPEN LINE FROM BUS 65215 [MANSFACE    230.00] TO BUS 67696 [BRDGR PP    230.00] CKT 1
SINGLE 139  : OPEN LINE FROM BUS 65220 [BRIDGER     230.00] TO BUS 66020 [MUSTANG     230.00] CKT 1
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# APPENDIX A-5-E

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SINGLE 140  : OPEN LINE FROM BUS 65220 [BRIDGER     230.00] TO BUS 66250 [PT ROCKS    230.00] CKT 1
SINGLE 141  : OPEN LINE FROM BUS 65220 [BRIDGER     230.00] TO BUS 66315 [ROCKSPGS    230.00] CKT 1
SINGLE 142  : OPEN LINE FROM BUS 65235 [BUFFALO     230.00] TO BUS 65293 [CARR DRA    230.00] CKT 1
SINGLE 143  : OPEN LINE FROM BUS 65235 [BUFFALO     230.00] TO BUS 65875 [KAYCEE      230.00] CKT 1
SINGLE 144  : OPEN LINE FROM BUS 65235 [BUFFALO     230.00] TO BUS 66335 [SHERIDAN    230.00] CKT 1
SINGLE 145  : OPEN LINE FROM BUS 65259 [CAMPWSVC    345.00] TO BUS 65260 [CAMP WIL    345.00] CKT 1
SINGLE 146  : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 65510 [EMERY       345.00] CKT 1
SINGLE 147  : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 65995 [MONA        345.00] CKT 1
SINGLE 148  : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 65995 [MONA        345.00] CKT 2
SINGLE 149  : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 65995 [MONA        345.00] CKT 3
SINGLE 150  : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 65995 [MONA        345.00] CKT 4
SINGLE 151  : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 66080 [NINETY S    345.00] CKT 1
SINGLE 152  : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 66080 [NINETY S    345.00] CKT 2
SINGLE 153  : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 66133 [OQUIRRH     345.00] CKT 1
SINGLE 154  : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 66133 [OQUIRRH     345.00] CKT 2
SINGLE 155  : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 66400 [SPAN FRK    345.00] CKT 1
SINGLE 156  : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 66510 [TERMINAL    345.00] CKT 1
SINGLE 157  : OPEN LINE FROM BUS 65293 [CARR DRA    230.00] TO BUS 66725 [WYODAK      230.00] CKT 1
SINGLE 158  : OPEN LINE FROM BUS 65300 [CASPERPP    230.00] TO BUS 65420 [DAVEJOHN    230.00] CKT 1
SINGLE 159  : OPEN LINE FROM BUS 65300 [CASPERPP    230.00] TO BUS 65420 [DAVEJOHN    230.00] CKT 2
SINGLE 160  : OPEN LINE FROM BUS 65300 [CASPERPP    230.00] TO BUS 66305 [RIVERTON    230.00] CKT 1
SINGLE 161  : OPEN LINE FROM BUS 65300 [CASPERPP    230.00] TO BUS 66410 [SPENCE      230.00] CKT 1
SINGLE 162  : OPEN LINE FROM BUS 65300 [CASPERPP    230.00] TO BUS 67531 [CLAIMJPR    230.00] CKT 1
SINGLE 163  : OPEN LINE FROM BUS 65311 [3 PK &1     345.00] TO BUS 65312 [THREE PK    345.00] CKT 1
SINGLE 164  : OPEN LINE FROM BUS 65311 [3 PK &1     345.00] TO BUS 66340 [SIGURD      345.00] CKT 1
SINGLE 165  : OPEN LINE FROM BUS 65312 [THREE PK    345.00] TO BUS 66280 [REDBUTTE    345.00] CKT 1
SINGLE 166  : OPEN LINE FROM BUS 65320 [CHAPPELC    230.00] TO BUS 65374 [CRAVENCK    230.00] CKT 1
SINGLE 167  : OPEN LINE FROM BUS 65320 [CHAPPELC    230.00] TO BUS 66050 [NAUGHTON    230.00] CKT 1
SINGLE 168  : OPEN LINE FROM BUS 65320 [CHAPPELC    230.00] TO BUS 67551 [JONAHGAS    230.00] CKT 1
SINGLE 169  : OPEN LINE FROM BUS 65320 [CHAPPELC    230.00] TO BUS 67555 [CHMNY BT    230.00] CKT 1
SINGLE 170  : OPEN LINE FROM BUS 65320 [CHAPPELC    230.00] TO BUS 67564 [JONFLD      230.00] CKT 1
SINGLE 171  : OPEN LINE FROM BUS 65374 [CRAVENCK    230.00] TO BUS 66011 [MONU PST    230.00] CKT 1
SINGLE 172  : OPEN LINE FROM BUS 65374 [CRAVENCK    230.00] TO BUS 66050 [NAUGHTON    230.00] CKT 1
SINGLE 173  : OPEN LINE FROM BUS 65394 [CURRANTC    345.00] TO BUS 65995 [MONA        345.00] CKT 1
SINGLE 174  : OPEN LINE FROM BUS 65420 [DAVEJOHN    230.00] TO BUS 65460 [DIFICULT    230.00] CKT 1
SINGLE 175  : OPEN LINE FROM BUS 65420 [DAVEJOHN    230.00] TO BUS 66745 [YELLOWCK    230.00] CKT 1
SINGLE 176  : OPEN LINE FROM BUS 65460 [DIFICULT    230.00] TO BUS 65975 [MINERS      230.00] CKT 1
SINGLE 177  : OPEN LINE FROM BUS 65510 [EMERY       345.00] TO BUS 65805 [HUNTNGTN    345.00] CKT 1
SINGLE 178  : OPEN LINE FROM BUS 65510 [EMERY       345.00] TO BUS 66340 [SIGURD      345.00] CKT 1
SINGLE 179  : OPEN LINE FROM BUS 65510 [EMERY       345.00] TO BUS 66340 [SIGURD      345.00] CKT 2
SINGLE 180  : OPEN LINE FROM BUS 65545 [EXXON WY    230.00] TO BUS 66010 [MONUMENT    230.00] CKT 1
SINGLE 181  : OPEN LINE FROM BUS 65555 [FIREHOLE    230.00] TO BUS 65895 [LITTLEMT    230.00] CKT 1
SINGLE 182  : OPEN LINE FROM BUS 65555 [FIREHOLE    230.00] TO BUS 66315 [ROCKSPGS    230.00] CKT 1
SINGLE 183  : OPEN LINE FROM BUS 65565 [FLAMGORG    230.00] TO BUS 65895 [LITTLEMT    230.00] CKT 1
SINGLE 184  : OPEN LINE FROM BUS 65575 [FRANNIE     230.00] TO BUS 65620 [GARLAND     230.00] CKT 1
SINGLE 185  : OPEN LINE FROM BUS 65575 [FRANNIE     230.00] TO BUS 66750 [YELOWTLP    230.00] CKT 1
SINGLE 186  : OPEN LINE FROM BUS 65580 [FT CREEK    230.00] TO BUS 65975 [MINERS      230.00] CKT 1
SINGLE 187  : OPEN LINE FROM BUS 65620 [GARLAND     230.00] TO BUS 66145 [OREBASIN    230.00] CKT 1
SINGLE 188  : OPEN LINE FROM BUS 65660 [GOOSE CK    230.00] TO BUS 66335 [SHERIDAN    230.00] CKT 1
SINGLE 189  : OPEN LINE FROM BUS 65660 [GOOSE CK    230.00] TO BUS 66750 [YELOWTLP    230.00] CKT 1
SINGLE 190  : OPEN LINE FROM BUS 65720 [GRASS CK    230.00] TO BUS 66145 [OREBASIN    230.00] CKT 1
SINGLE 191  : OPEN LINE FROM BUS 65720 [GRASS CK    230.00] TO BUS 66535 [THERMOPL    230.00] CKT 1
SINGLE 192  : OPEN LINE FROM BUS 65805 [HUNTNGTN    345.00] TO BUS 65995 [MONA        345.00] CKT 1
SINGLE 193  : OPEN LINE FROM BUS 65805 [HUNTNGTN    345.00] TO BUS 66224 [PINTO &1    345.00] CKT 1
SINGLE 194  : OPEN LINE FROM BUS 65805 [HUNTNGTN    345.00] TO BUS 66400 [SPAN FRK    345.00] CKT 1
SINGLE 195  : OPEN LINE FROM BUS 65875 [KAYCEE      230.00] TO BUS 65955 [MIDWEST     230.00] CKT 1
SINGLE 196  : OPEN LINE FROM BUS 65945 [MIDVALLY    345.00] TO BUS 66080 [NINETY S    345.00] CKT 1
SINGLE 197  : OPEN LINE FROM BUS 65945 [MIDVALLY    345.00] TO BUS 66510 [TERMINAL    345.00] CKT 1
SINGLE 198  : OPEN LINE FROM BUS 65955 [MIDWEST     230.00] TO BUS 67531 [CLAIMJPR    230.00] CKT 1
SINGLE 199  : OPEN LINE FROM BUS 65975 [MINERS      230.00] TO BUS 66240 [PLATTE      230.00] CKT 1
SINGLE 200  : OPEN LINE FROM BUS 65995 [MONA        345.00] TO BUS 66340 [SIGURD      345.00] CKT 1
SINGLE 201  : OPEN LINE FROM BUS 65995 [MONA        345.00] TO BUS 66340 [SIGURD      345.00] CKT 2
SINGLE 202  : OPEN LINE FROM BUS 66010 [MONUMENT    230.00] TO BUS 66011 [MONU PST    230.00] CKT 1
SINGLE 203  : OPEN LINE FROM BUS 66010 [MONUMENT    230.00] TO BUS 66011 [MONU PST    230.00] CKT 2
SINGLE 204  : OPEN LINE FROM BUS 66010 [MONUMENT    230.00] TO BUS 66325 [SO TRONA    230.00] CKT 1
SINGLE 205  : OPEN LINE FROM BUS 66011 [MONU PST    230.00] TO BUS 66050 [NAUGHTON    230.00] CKT 1
SINGLE 206  : OPEN LINE FROM BUS 66020 [MUSTANG     230.00] TO BUS 66410 [SPENCE      230.00] CKT 1
SINGLE 207  : OPEN LINE FROM BUS 66050 [NAUGHTON    230.00] TO BUS 66565 [TREASTON    230.00] CKT 1
SINGLE 208  : OPEN LINE FROM BUS 66080 [NINETY S    345.00] TO BUS 66510 [TERMINAL    345.00] CKT 1
SINGLE 209  : OPEN LINE FROM BUS 66133 [OQUIRRH     345.00] TO BUS 66510 [TERMINAL    345.00] CKT 1
SINGLE 210  : OPEN LINE FROM BUS 66133 [OQUIRRH     345.00] TO BUS 66510 [TERMINAL    345.00] CKT 2
SINGLE 211  : OPEN LINE FROM BUS 66180 [PALISADE    230.00] TO BUS 66266 [RAVEN       230.00] CKT 1
SINGLE 212  : OPEN LINE FROM BUS 66180 [PALISADE    230.00] TO BUS 66315 [ROCKSPGS    230.00] CKT 1
SINGLE 213  : OPEN LINE FROM BUS 66195 [PAROWAN     230.00] TO BUS 66345 [SIGURD      230.00] CKT 1
SINGLE 214  : OPEN LINE FROM BUS 66210 [PAVANT      230.00] TO BUS 66345 [SIGURD      230.00] CKT 1
SINGLE 215  : OPEN LINE FROM BUS 66224 [PINTO &1    345.00] TO BUS 66225 [PINTO       345.00] CKT 1
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# APPENDIX A-5-E

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SINGLE 216  : OPEN LINE FROM BUS 66225 [PINTO      345.00] TO BUS 66235 [PINTO PS    345.00] CKT 1
SINGLE 217  : OPEN LINE FROM BUS 66240 [PLATTE     230.00] TO BUS 67499 [LATHAM      230.00] CKT 1
SINGLE 218  : OPEN LINE FROM BUS 66250 [PT ROCKS   230.00] TO BUS 66315 [ROCKSPGS    230.00] CKT 1
SINGLE 219  : OPEN LINE FROM BUS 66250 [PT ROCKS   230.00] TO BUS 67529 [BITTERCK    230.00] CKT 1
SINGLE 220  : OPEN LINE FROM BUS 66266 [RAVEN      230.00] TO BUS 66670 [WESTVACO    230.00] CKT 1
SINGLE 221  : OPEN LINE FROM BUS 66280 [REDBUTTE   345.00] TO BUS 66281 [RED B SVC   345.00] CKT 1
SINGLE 222  : OPEN LINE FROM BUS 66280 [REDBUTTE   345.00] TO BUS 67657 [UTAH-NEV    345.00] CKT 1
SINGLE 223  : OPEN LINE FROM BUS 66305 [RIVERTON   230.00] TO BUS 66535 [THERMOPL    230.00] CKT 1
SINGLE 224  : OPEN LINE FROM BUS 66305 [RIVERTON   230.00] TO BUS 66740 [WYOPO      230.00] CKT 1
SINGLE 225  : OPEN LINE FROM BUS 66315 [ROCKSPGS   230.00] TO BUS 67553 [WIND RIV   230.00] CKT 1
SINGLE 226  : OPEN LINE FROM BUS 66340 [SIGURD     345.00] TO BUS 66345 [SIGURD     230.00] CKT 1
SINGLE 227  : OPEN LINE FROM BUS 66340 [SIGURD     345.00] TO BUS 66345 [SIGURD     230.00] CKT 2
SINGLE 228  : OPEN LINE FROM BUS 66345 [SIGURD     230.00] TO BUS 66355 [SIGURDPS   230.00] CKT 1
SINGLE 229  : OPEN LINE FROM BUS 66476 [SYRACUSE   345.00] TO BUS 66510 [TERMINAL   345.00] CKT 1
SINGLE 230  : OPEN LINE FROM BUS 67499 [LATHAM     230.00] TO BUS 67530 [ECHOSPRG   230.00] CKT 1
SINGLE 231  : OPEN LINE FROM BUS 67530 [ECHOSPRG   230.00] TO BUS 67770 [CRESTON    230.00] CKT 1
SINGLE 232  : OPEN LINE FROM BUS 67551 [JONAHGAS   230.00] TO BUS 67554 [WINDR PS   230.00] CKT 1
SINGLE 233  : OPEN LINE FROM BUS 67551 [JONAHGAS   230.00] TO BUS 67564 [JONFLD     230.00] CKT 1
SINGLE 234  : OPEN LINE FROM BUS 67552 [PARDISE    230.00] TO BUS 67554 [WINDR PS   230.00] CKT 1
SINGLE 235  : OPEN LINE FROM BUS 67552 [PARDISE    230.00] TO BUS 67555 [CHMNY BT   230.00] CKT 1
SINGLE 236  : OPEN LINE FROM BUS 67552 [PARDISE    230.00] TO BUS 67564 [JONFLD     230.00] CKT 1
SINGLE 237  : OPEN LINE FROM BUS 67553 [WIND RIV   230.00] TO BUS 67554 [WINDR PS   230.00] CKT 1
SINGLE 239  : OPEN LINE FROM BUS 60020 [AMFLS      138.00] TO BUS 65920 [MALAD      138.00] CKT 1
SINGLE 240  : OPEN LINE FROM BUS 60030 [BLACKFT    161.00] TO BUS 65670 [GOSHEN     161.00] CKT 1
SINGLE 244  : OPEN LINE FROM BUS 60084 [3MIKNOLL   345.00] TO BUS 65290 [CARIBO 2   138.00] CKT 2
SINGLE 252  : OPEN LINE FROM BUS 62061 [RMRK PHA   161.00] TO BUS 66755 [YELOWTLP   161.00] CKT 1
SINGLE 253  : OPEN LINE FROM BUS 62084 [DILLON S   161.00] TO BUS 65155 [BIGGRASS   161.00] CKT 1
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## *N-2 Contingency List:*

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LABEL          EVENTS
BL323        : OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 65145 [BENLOMND   138.00] CKT 1
               OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 65140 [BENLOMND   230.00] CKT 1
BL325        : OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 66510 [TERMINAL   345.00] CKT 1
               OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 65140 [BENLOMND   230.00] CKT 1
BL326        : OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 66476 [SYRACUSE   345.00] CKT 1
               OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 65140 [BENLOMND   230.00] CKT 1
BL343        : OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 65145 [BENLOMND   138.00] CKT 1
               OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 65140 [BENLOMND   230.00] CKT 2
BL345        : OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 66510 [TERMINAL   345.00] CKT 1
               OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 65140 [BENLOMND   230.00] CKT 2
BL346        : OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 66476 [SYRACUSE   345.00] CKT 1
               OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 60060 [BORAH      345.00] CKT 1
BL366        : OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 60060 [BORAH      345.00] CKT 1
               OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 65140 [BENLOMND   230.00] CKT 2
BLTRMBLSYR   : OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 66510 [TERMINAL   345.00] CKT 1
               OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 66476 [SYRACUSE   345.00] CKT 1
BLBORTRSBRY  : OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 60060 [BORAH      345.00] CKT 1
               OPEN LINE FROM BUS 66565 [TREASTON   230.00] TO BUS 60073 [BRADY      230.00] CKT 1
BL202        : OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 65140 [BENLOMND   230.00] CKT 1
               OPEN LINE FROM BUS 65145 [BENLOMND   138.00] TO BUS 65140 [BENLOMND   230.00] CKT 1
BL222        : OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 65140 [BENLOMND   230.00] CKT 1
               OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 65140 [BENLOMND   230.00] CKT 2
BL242        : OPEN LINE FROM BUS 65135 [BENLOMND   345.00] TO BUS 65140 [BENLOMND   230.00] CKT 2
               OPEN LINE FROM BUS 65140 [BENLOMND   230.00] TO BUS 65145 [BENLOMND   138.00] CKT 2
BL244        : OPEN LINE FROM BUS 65140 [BENLOMND   230.00] TO BUS 66050 [NAUGHTON   230.00] CKT 1
               OPEN LINE FROM BUS 65140 [BENLOMND   230.00] TO BUS 65145 [BENLOMND   138.00] CKT 2
BL245        : OPEN LINE FROM BUS 65140 [BENLOMND   230.00] TO BUS 65160 [BIRCH CK    230.00] CKT 1
               OPEN LINE FROM BUS 65140 [BENLOMND   230.00] TO BUS 65145 [BENLOMND   138.00] CKT 2
BLNAUBLBIR   : OPEN LINE FROM BUS 65140 [BENLOMND   230.00] TO BUS 66050 [NAUGHTON   230.00] CKT 1
               OPEN LINE FROM BUS 65140 [BENLOMND   230.00] TO BUS 65160 [BIRCH CK    230.00] CKT 1
JB330        : OPEN LINE FROM BUS 60085 [BRIDGER    345.00] TO BUS 65220 [BRIDGER    230.00] CKT 1
               OPEN LINE FROM BUS 60085 [BRIDGER    345.00] TO BUS 65220 [BRIDGER    230.00] CKT 3
               OPEN LINE FROM BUS 60086 [BRIDGER1    22.000] TO BUS 60085 [BRIDGER    345.00] CKT 1
JB332        : OPEN LINE FROM BUS 60085 [BRIDGER    345.00] TO BUS 60060 [BORAH      345.00] CKT &1
               OPEN LINE FROM BUS 60086 [BRIDGER1    22.000] TO BUS 60085 [BRIDGER    345.00] CKT 1
JB334        : OPEN LINE FROM BUS 60085 [BRIDGER    345.00] TO BUS 65220 [BRIDGER    230.00] CKT 2
               OPEN LINE FROM BUS 60085 [BRIDGER    345.00] TO BUS 60060 [BORAH      345.00] CKT &1
JB336        : OPEN LINE FROM BUS 60085 [BRIDGER    345.00] TO BUS 65220 [BRIDGER    230.00] CKT 1
               OPEN LINE FROM BUS 60085 [BRIDGER    345.00] TO BUS 65220 [BRIDGER    230.00] CKT 3
               OPEN LINE FROM BUS 60087 [BRIDGER2    22.000] TO BUS 60085 [BRIDGER    345.00] CKT 1
JB338        : OPEN LINE FROM BUS 60087 [BRIDGER2    22.000] TO BUS 60085 [BRIDGER    345.00] CKT 1
               OPEN LINE FROM BUS 60085 [BRIDGER    345.00] TO BUS 60190 [KINPORT    345.00] CKT &1
JB340        : OPEN LINE FROM BUS 60085 [BRIDGER    345.00] TO BUS 65220 [BRIDGER    230.00] CKT 2
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                 OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 60190 [KINPORT     345.00] CKT &1
JB342          : OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 65220 [BRIDGER     230.00] CKT 1
                 OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 65220 [BRIDGER     230.00] CKT 3
                 OPEN LINE FROM BUS 60088 [BRIDGER3    22.000] TO BUS 60085 [BRIDGER     345.00] CKT 1
JB344          : OPEN LINE FROM BUS 60088 [BRIDGER3    22.000] TO BUS 60085 [BRIDGER     345.00] CKT 1
                 OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 60092 [BRIDGE&B    345.00] CKT 1
JB346          : OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 65220 [BRIDGER     230.00] CKT 2
                 OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 60092 [BRIDGE&B    345.00] CKT 1
JB352          : OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 65220 [BRIDGER     230.00] CKT 1
                 OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 65220 [BRIDGER     230.00] CKT 3
                 OPEN LINE FROM BUS 60089 [BRIDGER4    22.000] TO BUS 60085 [BRIDGER     345.00] CKT 1
JB354          : OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 65220 [BRIDGER     230.00] CKT 2
                 OPEN LINE FROM BUS 60089 [BRIDGER4    22.000] TO BUS 60085 [BRIDGER     345.00] CKT 1
JBGOSJBKIN     : OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 60092 [BRIDGE&B    345.00] CKT 1
                 OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 60190 [KINPORT     345.00] CKT &1
                 OPEN LINE FROM BUS 60088 [BRIDGER3    22.000] TO BUS 60085 [BRIDGER     345.00] CKT 1
                 OPEN LINE FROM BUS 60089 [BRIDGER4    22.000] TO BUS 60085 [BRIDGER     345.00] CKT 1
JBGOSJBBOR     : OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 60092 [BRIDGE&B    345.00] CKT 1
                 OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 60060 [BORAH       345.00] CKT &1
                 OPEN LINE FROM BUS 60088 [BRIDGER3    22.000] TO BUS 60085 [BRIDGER     345.00] CKT 1
                 OPEN LINE FROM BUS 60089 [BRIDGER4    22.000] TO BUS 60085 [BRIDGER     345.00] CKT 1
JBKINJBBOR     : OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 60190 [KINPORT     345.00] CKT &1
                 OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 60060 [BORAH       345.00] CKT &1
                 OPEN LINE FROM BUS 60088 [BRIDGER3    22.000] TO BUS 60085 [BRIDGER     345.00] CKT 1
                 OPEN LINE FROM BUS 60089 [BRIDGER4    22.000] TO BUS 60085 [BRIDGER     345.00] CKT 1
JB292          : OPEN LINE FROM BUS 65220 [BRIDGER     230.00] TO BUS 66020 [MUSTANG     230.00] CKT 1
                 OPEN LINE FROM BUS 65220 [BRIDGER     230.00] TO BUS 66250 [PT ROCKS    230.00] CKT 1
                 OPEN LINE FROM BUS 66315 [ROCKSPGS    230.00] TO BUS 66250 [PT ROCKS    230.00] CKT 1
JB294          : OPEN LINE FROM BUS 65220 [BRIDGER     230.00] TO BUS 66315 [ROCKSPGS    230.00] CKT 1
                 OPEN LINE FROM BUS 65220 [BRIDGER     230.00] TO BUS 66250 [PT ROCKS    230.00] CKT 1
                 OPEN LINE FROM BUS 66315 [ROCKSPGS    230.00] TO BUS 66250 [PT ROCKS    230.00] CKT 1
JB316          : OPEN LINE FROM BUS 65220 [BRIDGER     230.00] TO BUS 66315 [ROCKSPGS    230.00] CKT 1
                 OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 65220 [BRIDGER     230.00] CKT 2
JB348          : OPEN LINE FROM BUS 65220 [BRIDGER     230.00] TO BUS 66020 [MUSTANG     230.00] CKT 1
                 OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 65220 [BRIDGER     230.00] CKT 1
                 OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 65220 [BRIDGER     230.00] CKT 3
CW322          : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 65995 [MONA        345.00] CKT 3
                 OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 66510 [TERMINAL    345.00] CKT 1
CW323          : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 65995 [MONA        345.00] CKT 1
                 OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 66133 [OQUIRRH     345.00] CKT 1
CW325          : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 66400 [SPAN FRK    345.00] CKT 1
                 OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 66080 [NINETY S    345.00] CKT 1
CWTRMCWOQR     : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 66510 [TERMINAL    345.00] CKT 1
                 OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 66133 [OQUIRRH     345.00] CKT 1
CW90S1&2       : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 66080 [NINETY S    345.00] CKT 1
                 OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 66080 [NINETY S    345.00] CKT 2
CWMON2,4       : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 65995 [MONA        345.00] CKT 2
                 OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 65995 [MONA        345.00] CKT 4
CWMON1,3       : OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 65995 [MONA        345.00] CKT 1
                 OPEN LINE FROM BUS 65260 [CAMP WIL    345.00] TO BUS 65995 [MONA        345.00] CKT 3
CENTRAL XFMS:    OPEN LINE FROM BUS 66280 [REDBUTTE    345.00] TO BUS 65315 [CENTRAL     138.00] CKT 1
                 OPEN LINE FROM BUS 66280 [REDBUTTE    345.00] TO BUS 65315 [CENTRAL     138.00] CKT 2
DJ204          : OPEN LINE FROM BUS 65420 [DAVEJOHN    230.00] TO BUS 65425 [DAVEJOHN    115.00] CKT 1
                 OPEN LINE FROM BUS 65420 [DAVEJOHN    230.00] TO BUS 73190 [STEGALL     230.00] CKT 1
DJ238          : OPEN LINE FROM BUS 65420 [DAVEJOHN    230.00] TO BUS 65300 [CASPERPP    230.00] CKT 1
                 OPEN LINE FROM BUS 65420 [DAVEJOHN    230.00] TO BUS 65445 [DAVEJON4    22.000] CKT 1
DJ268          : OPEN LINE FROM BUS 65420 [DAVEJOHN    230.00] TO BUS 73107 [LAR.RIVR    230.00] CKT 1
                 OPEN LINE FROM BUS 65420 [DAVEJOHN    230.00] TO BUS 65440 [DAVEJON3    13.800] CKT 1
EM303          : OPEN LINE FROM BUS 65510 [EMERY       345.00] TO BUS 65515 [EMERY       138.00] CKT 1
                 OPEN LINE FROM BUS 65500 [EHUNTR 3    22.000] TO BUS 65510 [EMERY       345.00] CKT 1
EM321          : OPEN LINE FROM BUS 65510 [EMERY       345.00] TO BUS 65805 [HUNTNGTN    345.00] CKT 1
                 OPEN LINE FROM BUS 65490 [EHUNTR 1    24.000] TO BUS 65510 [EMERY       345.00] CKT 1
                 OPEN LINE FROM BUS 65490 [EHUNTR 1    24.000] TO BUS 65510 [EMERY       345.00] CKT 2
EM323          : OPEN LINE FROM BUS 65510 [EMERY       345.00] TO BUS 66340 [SIGURD      345.00] CKT 1
                 OPEN LINE FROM BUS 65500 [EHUNTR 3    22.000] TO BUS 65510 [EMERY       345.00] CKT 1
EM324          : OPEN LINE FROM BUS 65510 [EMERY       345.00] TO BUS 66340 [SIGURD      345.00] CKT 2
                 OPEN LINE FROM BUS 65510 [EMERY       345.00] TO BUS 65515 [EMERY       138.00] CKT 1
EM341          : OPEN LINE FROM BUS 65510 [EMERY       345.00] TO BUS 65805 [HUNTNGTN    345.00] CKT 1
                 OPEN LINE FROM BUS 65510 [EMERY       345.00] TO BUS 65515 [EMERY       138.00] CKT 1
EM343          : OPEN LINE FROM BUS 65510 [EMERY       345.00] TO BUS 66340 [SIGURD      345.00] CKT 1
                 OPEN LINE FROM BUS 65510 [EMERY       345.00] TO BUS 65515 [EMERY       138.00] CKT 1
EMSIG1&2       : OPEN LINE FROM BUS 65510 [EMERY       345.00] TO BUS 66340 [SIGURD      345.00] CKT 1
                 OPEN LINE FROM BUS 65510 [EMERY       345.00] TO BUS 66340 [SIGURD      345.00] CKT 2
HT301          : OPEN LINE FROM BUS 65805 [HUNTNGTN    345.00] TO BUS 66400 [SPAN FRK    345.00] CKT 1
                 OPEN LINE FROM BUS 65805 [HUNTNGTN    345.00] TO BUS 65810 [HUNTNGTN    138.00] CKT 2
HT303          : OPEN LINE FROM BUS 65800 [HUNTN G2    22.000] TO BUS 65805 [HUNTNGTN    345.00] CKT 1
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                OPEN LINE FROM BUS 65800 [HUNTN G2    22.000] TO BUS 65805 [HUNTNGTN    345.00] CKT 2
                OPEN LINE FROM BUS 65805 [HUNTNGTN    345.00] TO BUS 65810 [HUNTNGTN    138.00] CKT 2
HT322         : OPEN LINE FROM BUS 65795 [HUNTN G1    22.000] TO BUS 65805 [HUNTNGTN    345.00] CKT 1
                OPEN LINE FROM BUS 65795 [HUNTN G1    22.000] TO BUS 65805 [HUNTNGTN    345.00] CKT 2
                OPEN LINE FROM BUS 65805 [HUNTNGTN    345.00] TO BUS 65510 [EMERY       345.00] CKT 1
HT323         : OPEN LINE FROM BUS 65800 [HUNTN G2    22.000] TO BUS 65805 [HUNTNGTN    345.00] CKT 1
                OPEN LINE FROM BUS 65800 [HUNTN G2    22.000] TO BUS 65805 [HUNTNGTN    345.00] CKT 2
                OPEN LINE FROM BUS 65805 [HUNTNGTN    345.00] TO BUS 65995 [MONA        345.00] CKT 1
MV324         : OPEN LINE FROM BUS 65945 [MIDVALLY  345.00] TO BUS 66080 [NINETY S    345.00] CKT 1
                OPEN LINE FROM BUS 65945 [MIDVALLY    345.00] TO BUS 65946 [MIDVALLY    138.00] CKT 1
MV344         : OPEN LINE FROM BUS 65945 [MIDVALLY  345.00] TO BUS 66510 [TERMINAL    345.00] CKT 1
                OPEN LINE FROM BUS 65945 [MIDVALLY    345.00] TO BUS 66080 [NINETY S    345.00] CKT 1
MV364         : OPEN LINE FROM BUS 65945 [MIDVALLY  345.00] TO BUS 66510 [TERMINAL    345.00] CKT 1
                OPEN LINE FROM BUS 65945 [MIDVALLY    345.00] TO BUS 65946 [MIDVALLY    138.00] CKT 2
MN345         : OPEN LINE FROM BUS 65995 [MONA      345.00] TO BUS 65805 [HUNTNGTN    345.00] CKT 1
                OPEN LINE FROM BUS 65995 [MONA        345.00] TO BUS 65260 [CAMP WIL    345.00] CKT 3
MN346         : OPEN LINE FROM BUS 65995 [MONA      345.00] TO BUS 66340 [SIGURD      345.00] CKT 1
                OPEN LINE FROM BUS 65995 [MONA        345.00] TO BUS 65260 [CAMP WIL    345.00] CKT 1
MN347         : OPEN LINE FROM BUS 65995 [MONA      345.00] TO BUS 66340 [SIGURD      345.00] CKT 2
                OPEN LINE FROM BUS 65995 [MONA        345.00] TO BUS 65260 [CAMP WIL    345.00] CKT 2
MN349         : OPEN LINE FROM BUS 65995 [MONA      345.00] TO BUS 26043 [INTERMT     345.00] CKT 2
                OPEN LINE FROM BUS 65995 [MONA        345.00] TO BUS 65260 [CAMP WIL    345.00] CKT 4
MNSG1&2       : OPEN LINE FROM BUS 65995 [MONA      345.00] TO BUS 66340 [SIGURD      345.00] CKT 1
                OPEN LINE FROM BUS 65995 [MONA        345.00] TO BUS 66340 [SIGURD      345.00] CKT 2
MT2           : OPEN LINE FROM BUS 66010 [MONUMENT  230.00] TO BUS 65545 [EXXON WY    230.00] CKT 1
                OPEN LINE FROM BUS 66010 [MONUMENT    230.00] TO BUS 65165 [BLACKSFK    230.00] CKT 1
MT4           : OPEN LINE FROM BUS 66010 [MONUMENT  230.00] TO BUS 65545 [EXXON WY    230.00] CKT 1
                OPEN LINE FROM BUS 66010 [MONUMENT    230.00] TO BUS 66011 [MONU PST    230.00] CKT 1
                OPEN LINE FROM BUS 66010 [MONUMENT    230.00] TO BUS 66011 [MONU PST    230.00] CKT 2
MT6           : OPEN LINE FROM BUS 66010 [MONUMENT  230.00] TO BUS 66325 [SO TRONA    230.00] CKT 1
                OPEN LINE FROM BUS 66010 [MONUMENT    230.00] TO BUS 66011 [MONU PST    230.00] CKT 1
                OPEN LINE FROM BUS 66010 [MONUMENT    230.00] TO BUS 66011 [MONU PST    230.00] CKT 2
MT8           : OPEN LINE FROM BUS 66010 [MONUMENT  230.00] TO BUS 66325 [SO TRONA    230.00] CKT 1
                OPEN LINE FROM BUS 66010 [MONUMENT    230.00] TO BUS 65165 [BLACKSFK    230.00] CKT 1
MT652         : OPEN LINE FROM BUS 66011 [MONU PST  230.00] TO BUS 65374 [CRAVENCK    230.00] CKT 1
                OPEN LINE FROM BUS 66011 [MONU PST    230.00] TO BUS 66010 [MONUMENT    230.00] CKT 2
MT656         : OPEN LINE FROM BUS 66011 [MONU PST  230.00] TO BUS 65374 [CRAVENCK    230.00] CKT 1
                OPEN LINE FROM BUS 66011 [MONU PST    230.00] TO BUS 66050 [NAUGHTON    230.00] CKT 1
MT660         : OPEN LINE FROM BUS 66011 [MONU PST  230.00] TO BUS 66050 [NAUGHTON    230.00] CKT 1
                OPEN LINE FROM BUS 66010 [MONUMENT    230.00] TO BUS 66011 [MONU PST    230.00] CKT 1
MT664         : OPEN LINE FROM BUS 66010 [MONUMENT  230.00] TO BUS 66011 [MONU PST    230.00] CKT 1
                OPEN LINE FROM BUS 66010 [MONUMENT    230.00] TO BUS 66011 [MONU PST    230.00] CKT 2
NT211         : OPEN LINE FROM BUS 66050 [NAUGHTON  230.00] TO BUS 66055 [NAUGT G1    18.000] CKT 1
                OPEN LINE FROM BUS 66050 [NAUGHTON    230.00] TO BUS 66011 [MONU PST    230.00] CKT 1
NT212         : OPEN LINE FROM BUS 66050 [NAUGHTON  230.00] TO BUS 66060 [NAUGT G2    20.000] CKT 1
                OPEN LINE FROM BUS 66050 [NAUGHTON    230.00] TO BUS 65160 [BIRCH CK    230.00] CKT 1
NT213         : OPEN LINE FROM BUS 66050 [NAUGHTON  230.00] TO BUS 66065 [NAUGT G3    24.000] CKT 1
                OPEN LINE FROM BUS 66050 [NAUGHTON    230.00] TO BUS 65140 [BENLOMND    230.00] CKT 1
NT214         : OPEN LINE FROM BUS 66050 [NAUGHTON  230.00] TO BUS 66040 [NAUGHTN1    138.00] CKT 2
                OPEN LINE FROM BUS 66050 [NAUGHTON    230.00] TO BUS 66565 [TREASTON    230.00] CKT 1
NT215         : OPEN LINE FROM BUS 66050 [NAUGHTON  230.00] TO BUS 66045 [NAUGHTN2    138.00] CKT 1
                OPEN LINE FROM BUS 66050 [NAUGHTON    230.00] TO BUS 65374 [CRAVENCK    230.00] CKT 1
90S303/304    : OPEN LINE FROM BUS 66080 [NINETY S  345.00] TO BUS 65260 [CAMP WIL    345.00] CKT 2
                OPEN LINE FROM BUS 66080 [NINETY S    345.00] TO BUS 66085 [NINETY S    138.00] CKT 1
90S321        : OPEN LINE FROM BUS 66080 [NINETY S  345.00] TO BUS 66085 [NINETY S    138.00] CKT 1
                OPEN LINE FROM BUS 66080 [NINETY S    345.00] TO BUS 66085 [NINETY S    138.00] CKT 2
90S323        : OPEN LINE FROM BUS 66080 [NINETY S  345.00] TO BUS 65260 [CAMP WIL    345.00] CKT 2
                OPEN LINE FROM BUS 66080 [NINETY S    345.00] TO BUS 65945 [MIDVALLY    345.00] CKT 1
90S324        : OPEN LINE FROM BUS 66080 [NINETY S  345.00] TO BUS 65260 [CAMP WIL    345.00] CKT 1
                OPEN LINE FROM BUS 66080 [NINETY S    345.00] TO BUS 66510 [TERMINAL    345.00] CKT 1
90MV90TM      : OPEN LINE FROM BUS 66080 [NINETY S  345.00] TO BUS 65945 [MIDVALLY    345.00] CKT 1
                OPEN LINE FROM BUS 66080 [NINETY S    345.00] TO BUS 66510 [TERMINAL    345.00] CKT 1
PT302         : OPEN LINE FROM BUS 66225 [PINTO     345.00] TO BUS 66235 [PINTO PS    345.00] CKT 1
                OPEN LINE FROM BUS 66225 [PINTO       345.00] TO BUS 66229 [PINTO  3    13.800] CKT 2
PL298         : OPEN LINE FROM BUS 66240 [PLATTE    230.00] TO BUS 66245 [PLATTE      115.00] CKT 1
PL304         : OPEN LINE FROM BUS 66240 [PLATTE    230.00] TO BUS 65975 [MINERS      230.00] CKT 1
RB341         : OPEN LINE FROM BUS 66280 [REDBUTTE  345.00] TO BUS 66274 [REDBUTTE    138.00] CKT 1
                OPEN LINE FROM BUS 66280 [REDBUTTE    345.00] TO BUS 65315 [CENTRAL     138.00] CKT 1
                OPEN LINE FROM BUS 66280 [REDBUTTE    345.00] TO BUS 65315 [CENTRAL     138.00] CKT 2
RB362         : OPEN LINE FROM BUS 66280 [REDBUTTE  345.00] TO BUS 65312 [THREE PK    345.00] CKT 1
                OPEN LINE FROM BUS 66280 [REDBUTTE    345.00] TO BUS 66274 [REDBUTTE    138.00] CKT 1
RV112         : OPEN LINE FROM BUS 66305 [RIVERTON  230.00] TO BUS 66535 [THERMOPL    230.00] CKT 1
                OPEN LINE FROM BUS 66305 [RIVERTON    230.00] TO BUS 66740 [WYOPO       230.00] CKT 1
RV138         : OPEN LINE FROM BUS 66305 [RIVERTON  230.00] TO BUS 73170 [RIVERTON    115.00] CKT 1
                OPEN LINE FROM BUS 66305 [RIVERTON    230.00] TO BUS 66740 [WYOPO       230.00] CKT 1
RV172         : OPEN LINE FROM BUS 66305 [RIVERTON  230.00] TO BUS 73170 [RIVERTON    115.00] CKT 1
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# APPENDIX A-5-E

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                OPEN LINE FROM BUS 66305 [RIVERTON    230.00] TO BUS 65300 [CASPERPP    230.00] CKT 1
RS128         : OPEN LINE FROM BUS 66315 [ROCKSPGS    230.00] TO BUS 66180 [PALISADE    230.00] CKT 1
                OPEN LINE FROM BUS 66315 [ROCKSPGS    230.00] TO BUS 66250 [PT ROCKS    230.00] CKT 1
RS132         : OPEN LINE FROM BUS 66315 [ROCKSPGS    230.00] TO BUS 66180 [PALISADE    230.00] CKT 1
                OPEN LINE FROM BUS 66315 [ROCKSPGS    230.00] TO BUS 65555 [FIREHOLE    230.00] CKT 1
RSPTRSJB      : OPEN LINE FROM BUS 66315 [ROCKSPGS    230.00] TO BUS 66250 [PT ROCKS    230.00] CKT 1
                OPEN LINE FROM BUS 66315 [ROCKSPGS    230.00] TO BUS 65220 [BRIDGER     230.00] CKT 1
SG302         : OPEN LINE FROM BUS 66340 [SIGURD      345.00] TO BUS 65995 [MONA        345.00] CKT 2
                OPEN LINE FROM BUS 66340 [SIGURD      345.00] TO BUS 66345 [SIGURD      230.00] CKT 1
SG303         : OPEN LINE FROM BUS 66340 [SIGURD      345.00] TO BUS 65510 [EMERY       345.00] CKT 2
                OPEN LINE FROM BUS 66340 [SIGURD      345.00] TO BUS 66345 [SIGURD      230.00] CKT 1
SG304         : OPEN LINE FROM BUS 66340 [SIGURD      345.00] TO BUS 65995 [MONA        345.00] CKT 1
                OPEN LINE FROM BUS 66340 [SIGURD      345.00] TO BUS 66345 [SIGURD      230.00] CKT 1
SG324         : OPEN LINE FROM BUS 66340 [SIGURD      345.00] TO BUS 65995 [MONA        345.00] CKT 1
                OPEN LINE FROM BUS 66340 [SIGURD      345.00] TO BUS 65510 [EMERY       345.00] CKT 1
SF327         : OPEN LINE FROM BUS 66400 [SPAN FRK    345.00] TO BUS 65260 [CAMP WIL    345.00] CKT 1
                OPEN LINE FROM BUS 66400 [SPAN FRK    345.00] TO BUS 66405 [SPAN FRK    138.00] CKT 1
SF345CLSD     : OPEN LINE FROM BUS 66400 [SPAN FRK    345.00] TO BUS 66405 [SPAN FRK    138.00] CKT 1
                OPEN LINE FROM BUS 66400 [SPAN FRK    345.00] TO BUS 66405 [SPAN FRK    138.00] CKT 2
SF347CLSD     : OPEN LINE FROM BUS 66400 [SPAN FRK    345.00] TO BUS 65260 [CAMP WIL    345.00] CKT 1
                OPEN LINE FROM BUS 66400 [SPAN FRK    345.00] TO BUS 65805 [HUNTNGTN    345.00] CKT 1
SF357         : OPEN LINE FROM BUS 66400 [SPAN FRK    345.00] TO BUS 65805 [HUNTNGTN    345.00] CKT 1
                OPEN LINE FROM BUS 66400 [SPAN FRK    345.00] TO BUS 66405 [SPAN FRK    138.00] CKT 1
TM304         : OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 66080 [NINETY S    345.00] CKT 1
                OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 66520 [TERMINAL    138.00] CKT 2
TM308         : OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 66133 [OQUIRRH     345.00] CKT 1
                OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 66520 [TERMINAL    138.00] CKT 2
TM309         : OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 65260 [CAMP WIL    345.00] CKT 1
                OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 66520 [TERMINAL    138.00] CKT 2
TM323         : OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 65945 [MIDVALLY    345.00] CKT 1
                OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 66520 [TERMINAL    138.00] CKT 2
TM324         : OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 66080 [NINETY S    345.00] CKT 1
                OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 66520 [TERMINAL    138.00] CKT 1
TM328         : OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 66133 [OQUIRRH     345.00] CKT 1
                OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 65135 [BENLOMND    345.00] CKT 1
TM329         : OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 65260 [CAMP WIL    345.00] CKT 1
                OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 66476 [SYRACUSE    345.00] CKT 1
TM348         : OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 65135 [BENLOMND    345.00] CKT 1
                OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 66520 [TERMINAL    138.00] CKT 1
TM349         : OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 66476 [SYRACUSE    345.00] CKT 1
                OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 66520 [TERMINAL    138.00] CKT 1
TMBLTMSY      : OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 65135 [BENLOMND    345.00] CKT 1
                OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 66476 [SYRACUSE    345.00] CKT 1
TM90TMMV      : OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 66080 [NINETY S    345.00] CKT 1
                OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 65945 [MIDVALLY    345.00] CKT 1
TMCWTMOQ      : OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 65260 [CAMP WIL    345.00] CKT 1
                OPEN LINE FROM BUS 66510 [TERMINAL    345.00] TO BUS 66133 [OQUIRRH     345.00] CKT 1
TH14          : OPEN LINE FROM BUS 66535 [THERMOPL    230.00] TO BUS 66305 [RIVERTON    230.00] CKT 1
                OPEN LINE FROM BUS 66535 [THERMOPL    230.00] TO BUS 66540 [THERPACE    115.00] CKT 1
TH16,220      : OPEN LINE FROM BUS 66535 [THERMOPL    230.00] TO BUS 65720 [GRASS CK    230.00] CKT 1
                OPEN LINE FROM BUS 66535 [THERMOPL    230.00] TO BUS 66540 [THERPACE    115.00] CKT 1
TH224         : OPEN LINE FROM BUS 66535 [THERMOPL    230.00] TO BUS 66305 [RIVERTON    230.00] CKT 1
                OPEN LINE FROM BUS 66535 [THERMOPL    230.00] TO BUS 65095 [BADWATER    230.00] CKT 1
TH228         : OPEN LINE FROM BUS 66535 [THERMOPL    230.00] TO BUS 66540 [THERPACE    115.00] CKT 1
                OPEN LINE FROM BUS 66535 [THERMOPL    230.00] TO BUS 65095 [BADWATER    230.00] CKT 1
TR220         : OPEN LINE FROM BUS 66565 [TREASTON    230.00] TO BUS 60073 [BRADY       230.00] CKT 1
                OPEN LINE FROM BUS 66565 [TREASTON    230.00] TO BUS 66570 [TREASTON    138.00] CKT 2
TR240         : OPEN LINE FROM BUS 66565 [TREASTON    230.00] TO BUS 66050 [NAUGHTON    230.00] CKT 1
                OPEN LINE FROM BUS 66565 [TREASTON    230.00] TO BUS 66570 [TREASTON    138.00] CKT 1
TR230CLSD     : OPEN LINE FROM BUS 66565 [TREASTON    230.00] TO BUS 60073 [BRADY       230.00] CKT 1
                OPEN LINE FROM BUS 66565 [TREASTON    230.00] TO BUS 66050 [NAUGHTON    230.00] CKT 1
TR232CLSD     : OPEN LINE FROM BUS 66565 [TREASTON    230.00] TO BUS 66570 [TREASTON    138.00] CKT 1
                OPEN LINE FROM BUS 66565 [TREASTON    230.00] TO BUS 66570 [TREASTON    138.00] CKT 2
TRBRJBKP      : OPEN LINE FROM BUS 66565 [TREASTON    230.00] TO BUS 60073 [BRADY       230.00] CKT 1
                OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 60190 [KINPORT     345.00] CKT &1
TRBRJBBO      : OPEN LINE FROM BUS 66565 [TREASTON    230.00] TO BUS 60073 [BRADY       230.00] CKT 1
                OPEN LINE FROM BUS 60085 [BRIDGER     345.00] TO BUS 60060 [BORAH       345.00] CKT &1
WY326         : OPEN LINE FROM BUS 66725 [WYODAK      230.00] TO BUS 65293 [CARR DRA    230.00] CKT 1
                OPEN LINE FROM BUS 66725 [WYODAK      230.00] TO BUS 73294 [HUGHES      230.00] CKT 1
WY334         : OPEN LINE FROM BUS 66725 [WYODAK      230.00] TO BUS 73148 [OSAGE       230.00] CKT 1
                OPEN LINE FROM BUS 66725 [WYODAK      230.00] TO BUS 66730 [WYODAK 1     22.000] CKT 1
YW278         : OPEN LINE FROM BUS 66750 [YELOWTLP    230.00] TO BUS 73229 [YELLOWBR    230.00] CKT 1
                OPEN LINE FROM BUS 66750 [YELOWTLP    230.00] TO BUS 66755 [YELOWTLP    161.00] CKT 1
YW284         : OPEN LINE FROM BUS 66750 [YELOWTLP    230.00] TO BUS 65660 [GOOSE CK    230.00] CKT 1
                OPEN LINE FROM BUS 66750 [YELOWTLP    230.00] TO BUS 62045 [BLGS PHA    230.00] CKT 1
YW286         : OPEN LINE FROM BUS 66750 [YELOWTLP    230.00] TO BUS 65575 [FRANNIE     230.00] CKT 1
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# APPENDIX A-5-E

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                OPEN LINE FROM BUS 66750 [YELOWTLP    230.00] TO BUS 62045 [BLGS PHA    230.00] CKT 1
YW290         : OPEN LINE FROM BUS 66750 [YELOWTLP    230.00] TO BUS 65575 [FRANNIE     230.00] CKT 1
                OPEN LINE FROM BUS 66750 [YELOWTLP    230.00] TO BUS 66755 [YELOWTLP    161.00] CKT 1
YW296         : OPEN LINE FROM BUS 66750 [YELOWTLP    230.00] TO BUS 65660 [GOOSE CK    230.00] CKT 1
                OPEN LINE FROM BUS 66750 [YELOWTLP    230.00] TO BUS 73229 [YELLOWBR    230.00] CKT 1
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# Appendix 4: Transient Stability Results—2015 Heavy Summer

| Fault Description | Line Segment Opened | Switchdeck File | WECC Result | Low Voltage (p.u.) | Low Voltage Bus # | Low Voltage Bus | Total Colstrip Gen | Path 8 | Path 80 | ATR 1 Action (cycles) | ATR 2 Action (cycles) | ATR 3 Action (cycles) | ATR 4 Action (cycles) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3-Phase Fault at Garrison 500 kV | Garrison -- Taft (both circuits) | sdk_grtt12m_mc_gr.txt | C | 0.7276 | 62154 | SLVRBOW 115 kV | 2260 | 885 | 14.9 | 10.4 | 0 | 11.4 | 0 |
| 1-Phase Fault at Garrison 500 kV | Garrison -- Taft (single circuit) | sdk_1grtt1m.txt | B | 0.8538 | 62030 | PTRSNFLT 230 kV | 2260 | 885 | 14.9 | 0 | 0 | 0 | 0 |
| 3-Phase Fault at Garrison 500 kV | Garrison -- Taft (single circuit) | sdk_3grtt1.txt | B | 0.8323 | 62030 | PTRSNFLT 230 kV | 2260 | 885 | 14.9 | 0 | 0 | 0 | 0 |
| 3-Phase Fault at Broadview 500 kV | Broadview -- Colstrip | sdk_3bvcs1.txt | B | 0.8538 | 62060 | COLSTRP 230 kV | 2260 | 885 | 14.9 | 10 | 0 | 11 | 0 |
| 1-Phase Fault at Broadview 500 kV | Broadview -- Colstrip | sdk_1bvcs1.txt | B | 0.8735 | 63010 | MILCTYDC 230 kV | 2260 | 885 | 14.9 | 12 | 0 | 13 | 0 |
| 3-Phase Fault at Taft 500 kV | Taft -- Bell | sdk_3ttbb.txt | B | 0.9183 | 62216 | LAVINAPM 100 kV | 2260 | 885 | 14.9 | 0 | 0 | 0 | 0 |
| 3-Phase Fault at Taft 500 kV | Taft -- Dworshak | sdk_3ttdw.txt | B | 0.8858 | 62030 | PTRSNFLT 230 kV | 2260 | 885 | 14.9 | 0 | 0 | 0 | 0 |
| 3-Phase Fault at Townsend 500 kV | Townsend -- Midpoint (MSTI) | sdk_tnmp.txt | B | 0.7827 | 62030 | PTRSNFLT 230 kV | 2260 | 885 | 14.9 | 0 | 0 | 0 | 0 |
| 3-Phase Fault at Midpoint 500 kV | Townsend -- Midpoint (MSTI) | sdk_mptn.txt | B | 0.8671 | 62030 | PTRSNFLT 230 kV | 2260 | 885 | 14.9 | 0 | 0 | 13.8 | 0 |
| 3-Phase Fault at Townsend 500 kV | Townsend -- Garrison (both circuits) | sdk_tngr12.txt | B | 0.7790 | 62250 | BGTMBERA 161 kV | 2260 | 885 | 14.9 | 10 | 0 | 11 | 0 |
| 3-Phase Fault at Townsend 500 kV | Townsend -- Garrison (single circuit) | sdk_tngr1.txt | B | 0.9128 | 62235 | MARTNSDA 100 kV | 2260 | 885 | 14.9 | 0 | 0 | 0 | 0 |
| 3-Phase Fault at Broadview 500 kV | Broadview -- Townsend (both circuits) | sdk_3bvtn12.txt | B | 0.8660 | 62325 | DUCKCR-R 161 kV | 2260 | 885 | 14.9 | 8 | 0 | 9 | 9 |
| 3-Phase Fault at Broadview 500 kV | Broadview -- Townsend (single circuit) | sdk_3bvtn1.txt | B | 0.8936 | 63010 | MILCTYDC 230 kV | 2260 | 885 | 14.9 | 0 | 0 | 0 | 0 |
| 3-Phase Fault at Midpoint 500 kV | Midpoint -- Summer Lake | sdk_mpsl.txt | B | 0.8904 | 62030 | PTRSNFLT 230 kV | 2260 | 885 | 14.9 | 0 | 0 | 0 | 0 |

APPENDIX A-5-E

# Appendix 4: Transient Stability Results—2010 Light Autumn

| Fault Description | Line Segment Opened | Switchdeck File | WECC Result | Low Voltage (p.u.) | Low Voltage Bus # | Low Voltage Bus | Total Colstrip Gen | Path 8 | Path 80 | ATR 1 Action (cycles) | ATR 2 Action (cycles) | ATR 3 Action (cycles) | ATR 4 Action (cycles) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3-Phase Fault at Garrison 500 kV | Garrison -- Taft (both circuits) | sdk_grtt12m_mc_gr.txt | B | 0.8678 | 62081 | COLSTRP 115 kV | 2324 | 2170 | 559.5 | 9.2 | 0 | 10.2 | 10.2 |
| 1-Phase Fault at Garrison 500 kV | Garrison -- Taft (single circuit) | sdk_1grtt1m.txt | B | 0.9138 | 62154 | SLVRBOW 115 kV | 2324 | 2170 | 559.5 | 0 | 0 | 0 | 13.8 |
| 3-Phase Fault at Garrison 500 kV | Garrison -- Taft (single circuit) | sdk_3grtt1.txt | B | 0.9045 | 62031 | CUTBANK 115 kV | 2324 | 2170 | 559.5 | 0 | 0 | 0 | 0 |
| 3-Phase Fault at Broadview 500 kV | Broadview -- Colstrip | sdk_3bvcs1.txt | B | 0.8855 | 62081 | COLSTRP 115 kV | 2324 | 2170 | 559.5 | 10 | 0 | 0 | 11 |
| 1-Phase Fault at Broadview 500 kV | Broadview -- Colstrip | sdk_1bvcs1.txt | B | 0.9000 | 63010 | MILCTYDC 230 kV | 2324 | 2170 | 559.5 | 0 | 0 | 0 | 13.8 |
| 3-Phase Fault at Taft 500 kV | Taft -- Bell | sdk_ttbb.txt | B | 0.9366 | 62031 | CUTBANK 115 kV | 2324 | 2170 | 559.5 | 0 | 0 | 0 | 0 |
| 3-Phase Fault at Taft 500 kV | Taft -- Dworshak | sdk_ttdw.txt | B | 0.9421 | 62351 | HRSHOEGN 34.5 kV | 2324 | 2170 | 559.5 | 0 | 0 | 0 | 0 |
| 3-Phase Fault at Townsend 500 kV | Townsend -- Midpoint (MSTI) | sdk_tnmp.txt | B | 0.9402 | 63010 | MILCTYDC 230 kV | 2324 | 2170 | 559.5 | 0 | 0 | 0 | 0 |
| 3-Phase Fault at Midpoint 500 kV | Townsend -- Midpoint (MSTI) | sdk_mptn.txt | B | 0.9545 | 73216 | WINDRIVR 115 kV | 2324 | 2170 | 559.5 | 0 | 0 | 0 | 0 |
| 3-Phase Fault at Townsend 500 kV | Townsend -- Garrison (both circuits) | sdk_tngr12.txt | B | 0.8165 | 62081 | COLSTRP 115 kV | 2324 | 2170 | 559.5 | 9.2 | 0 | 10.2 | 10.2 |
| 3-Phase Fault at Townsend 500 kV | Townsend -- Garrison (single circuit) | sdk_tngr1.txt | B | 0.9344 | 62235 | MARTNSDA 100 kV | 2324 | 2170 | 559.5 | 0 | 0 | 0 | 0 |
| 3-Phase Fault at Broadview 500 kV | Broadview -- Townsend (both circuits) | sdk_3bvtn12.txt | B | 0.8274 | 9998 | DCEAST 230 kV | 2324 | 2170 | 559.5 | 8 | 0 | 9 | 9 |
| 3-Phase Fault at Broadview 500 kV | Broadview -- Townsend (single circuit) | sdk_3bvtn1.txt | B | 0.9191 | 62235 | MARTNSDA 100 kV | 2324 | 2170 | 559.5 | 0 | 0 | 0 | 0 |
| 3-Phase Fault at Midpoint 500 kV | Midpoint -- Summer Lake | sdk_mpsl.txt | B | 0.9751 | 60225 | MICRON 138 kV | 2324 | 2170 | 559.5 | 0 | 0 | 0 | 0 |

APPENDIX A-5-E

APPENDIX A-5-F

# Rocky Mountain Area Transmission Study

Connecting the region today
for the energy needs of the future

**September 2004**

# APPENDIX A-5-F

**APPENDIX A-5-F**

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# Executive Summary

On August 22, 2003, Wyoming Governor Dave Freudenthal and Utah Governor Michael Leavitt announced the formation of the Rocky Mountain Area Transmission Study (RMATS). They did so because the electric power industry has been reluctant to invest in new transmission infrastructure due to protracted regulatory uncertainties. Without such investment, the region[1] may not be able to tap lower cost coal and wind generation for Rocky Mountain load growth, or to export generation to other parts of the Western Interconnection. Making greater use of the region's coal and wind resources can lower power costs to consumers and reduce the volatility of electricity prices.

The Governors created a charter that established the guiding principles for the RMATS effort, which are:

- Include all interested stakeholder individuals and groups;
- Work together for effective solutions in a balanced, open and inclusive public process;
- Conduct analysis of generation and transmission alternatives based on data, assumptions, and scenarios developed by participating stakeholders;
- Consider every need, generation technology and location option that is appropriate for the region;
- Evaluate all potential transmission alternatives within the region;
- Identify the costs and benefits of generation and transmission options for serving the electricity needs of consumers that make operational, economic, and environmental sense for the region; and,
- Cooperate and coordinate with the west-wide Seams Steering Group-Western Interconnection (SSG-WI) planning effort and other sub-regional planning efforts and with WECC in order to ensure maintaining or improving system reliability.

The RMATS footprint covers the States of Colorado, Idaho, Montana, Utah and Wyoming.

In the first phase of the RMATS process, stakeholders joined in work groups on load forecasting, resource additions, and transmission additions which developed assumptions that were input into a production cost model to examine the value of potential transmission expansion under different generation scenarios. The information used in the modeling effort is publicly available. A steering committee guided the integration of the activities of the work groups and the RMATS modeling team to: (1) evaluate the overall economics of transmission expansion under four generation scenarios; and, (2) identify transmission projects that may be economic and feasible because of the savings they provide Rocky Mountain region and elsewhere in the West. The analysis tested the sensitivity of the results under a variety of assumptions, such as high and low hydroelectric generation, high and low natural gas prices, significant improvements in energy efficiency, and potential imposition of constraints on carbon dioxide emissions.

[1] In this Report the term "region will refer to the Rocky Mountain area of the states of Idaho, Montana, Wyoming, Utah and Colorado except where there are references to the Seams Steering Group-Western Interconnection (SSG-WI) planning effort where the Rocky Mountain area will be referred to as a sub-region.

The most feasible transmission additions are recommended to proceed to Phase II. The purpose of Phase II is to conduct transmission technical studies, address siting and cost assignment and recovery issues, identify project sponsors, and arrange project financing. To jumpstart Phase II work, RMATS formed a cost allocation and cost recovery team to begin identifying promising approaches to financing the recommended transmission additions. The team also recommended process improvements that would (1) make it more likely that economic transmission expansion projects would be implemented; and, (2) set the stage for continuing improvements in transmission planning.

Because of the potential for significant new wind generation in the Rocky Mountain region in the near term and the unique characteristics of wind development and operation, RMATS also formed a work group to explore ways in which the existing transmission system could be used more efficiently to enable the development of additional wind generation. The work group found, after comparing wind output and existing flow data on three specific transmission paths in the region, that there is substantial physical capacity available at most times of the year that current operational practices and tariff requirements do not make available to wind on a long-term basis. Additional study work will be required to take into account the scheduled use of the transmission system as well as the actual power flows. There is potential for wind to make better use of the existing system through innovative tariff products. A "conditional firm" product would offer firm service except for certain defined periods, and a long term "priority non-firm" product would offer a high priority non-firm service on a long-term contractual basis. Other resources may find this product attractive also.

Contractual, tariff and operating practices limit the use of existing transmission assets. Such institutional impediments also limit transmission access and raise the cost of operating and expanding the grid. Removing or reducing these impediments would enable the existing system to be used more fully and optimally, and potentially allow some capital investment in grid expansion to be deferred. The RMATS simulation includes the benefits of a regionally operated system that avoids rate pancaking, consolidates control areas, and removes other institutional impediments to fuller use of the existing system.

## Recommended Projects

The RMATS process identified two projects that are needed to serve load in the near-term, involve limited investment and provide significant benefits:

- A transformer replacement at Flaming Gorge to increase transfer capacity on existing lines in southwest Wyoming and northeast Utah; and
- A phase shifter on the line between Montana and Idaho to increase the control of actual flow and usability of the path from Montana.

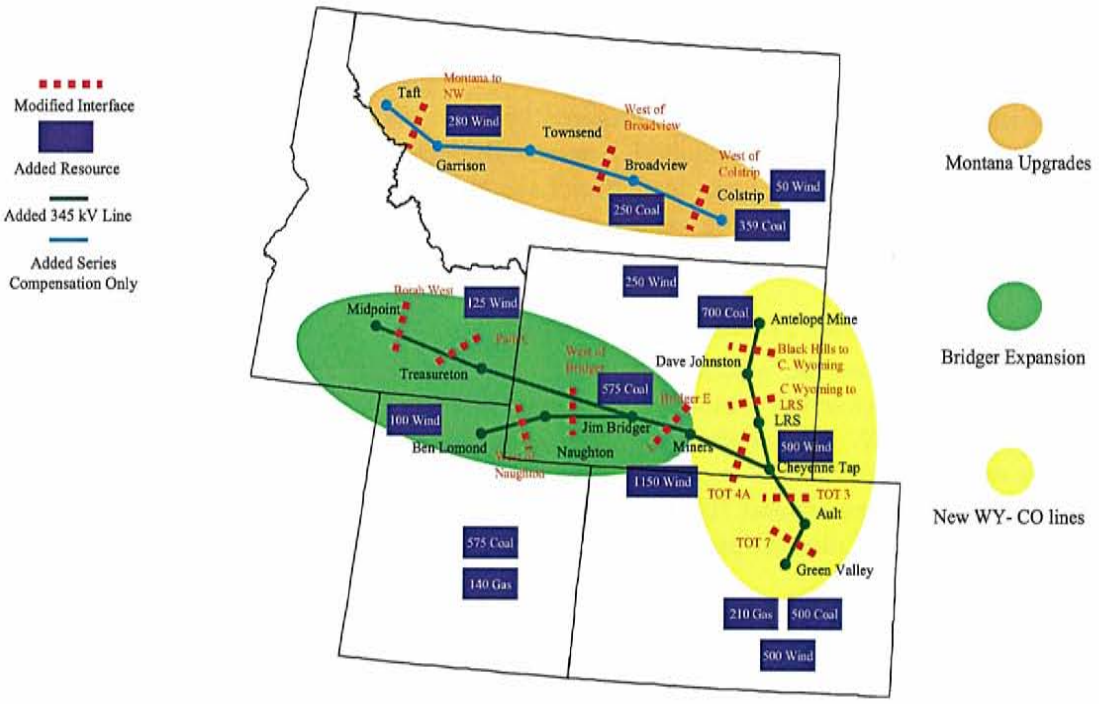
The Western Area Power Administration will replace the transformers at Flaming Gorge in 2006; and Northwestern Energy, Idaho Power Company and PacifiCorp are examining the addition of the phase shifter.

### Recommendation 1: Expansion Projects within the Rocky Mountain Footprint

RMATS identified projects that would provide significant economic benefit over the longer term. There are three discreet transmission projects within the RMATS footprint included in Recommendation 1, and several options in Recommendation 2 for longer-term development. Figure E-1 shows the three discrete projects included in Recommendation 1: Montana Upgrades

(tan oval), Bridger Expansion (green oval), and Wyoming to Colorado Project (yellow oval). The capital cost for these three transmission expansion projects is estimated to be $970 million. An economic comparison of Recommendation 1 with the two Reference Cases indicates these three transmission expansion projects are cost justified and capable of producing annual net savings of $61 million to $531 million per year. While each project is discrete, the three projects together provide the greatest benefit to the region.

*Figure E- 1: Recommendation 1 Projects*




Recommendation 1 is predicated on the new wind capacity and coal-fired generation additions shown on the map. The new capacity will meet expected load growth in the Rocky Mountain region for the 2013 timeframe.

### *Montana System Upgrade Project*

This project upgrades the existing Montana 500 kV transmission system to enable exports from the Rocky Mountain region to the Pacific Northwest and does not require new transmission lines. By installing series compensation in the 500 kV lines from Colstrip to Taft, adding a 500/230 kV autotransformer at Colstrip, and adding two new substations on the 500 kV transmission system near Ringling and Missoula, transfer capacity can be increased by an estimated 500 MW. The capital cost for the Montana System Upgrade project is estimated to be $72 million. The resource additions assumed include 330 MW of nameplate capacity wind generation and 609 MW of coal-fired generation in Montana.

The Montana System Upgrade is expected to have limited siting requirements. All the impacts are local in nature and a new transmission corridor is not required. The additions at the Colstrip and Broadview buses constitute upgrades to existing substation sites and will have little if any

environmental impact. The new substation sites will have minimal siting requirements. Acquisition of sufficient land for the substations may be the most serious issue. Local opposition may be reduced if future ties to the lower voltage systems at these two locations reduce the requirements for new transmission in these areas as loads grow.

### *Bridger Expansion Project*

Expansion of the Bridger 345 kV transmission system involves the addition of 345 kV transmission facilities from Miners to Bridger in Wyoming and from Bridger to Ben Lomond in Utah and to Midpoint in Idaho. These additions would increase transfer capacity by an estimated 1,350 MW. Resource additions are assumed to include 1,375 MW of wind and 575 MW of coal-fired generation in southwest Wyoming and southern Idaho. The capital cost of the Bridger Expansion project is estimated to be $580 million.

A new transmission corridor may be required between Naughton and northern Utah, and a new transmission corridor will be required between Bridger and Midpoint (potentially traversing an environmentally sensitive area north of Bear Lake in southern Idaho). New substation sites could have siting requirements. Siting issues may be reduced through use of existing lower voltage transmission corridors.

### *Wyoming to Colorado Transmission Project*

This project involves the addition of a 345 kV line from northeastern Wyoming across the constrained path between Wyoming and Colorado to Denver. The new line is estimated to increase capacity by 500 MW. The addition of series compensation to this new line (and potentially other lines) is estimated to increase capacity by an additional 250 MW. Assumed resource additions are 500 MW of wind capacity and 700 MW of coal-fired generation capacity. The capital requirements for the Wyoming to Colorado project are an estimated $318 million.

The new 345 kV line would have substation interconnections in Wyoming potentially in the Dave Johnston, Laramie River Station and Cheyenne areas. It would also require an interconnection in northern Colorado, perhaps at the Ault substation, with a final destination near the Green Valley substation northeast of Denver. Congestion resulting from the generation additions would be reduced from an estimated high of 73 percent to below 30 percent with these line additions. Substantial siting work is expected. Siting issues may be reduced through use of existing lower voltage transmission corridors.

**Recommendation 2: Export Projects beyond the Rocky Mountain Footprint**

In addition to the projects in Recommendation 1, RMATS recommends transmission expansions that extend beyond the Rocky Mountain States to enable exports of generation. This is a longer-term export proposal that: (1) includes the generation assumed for the projects in Recommendation 1; (2) assumes construction of an additional 3,900 MW of coal generation and remote wind generation; and, (3) builds two export paths to the West Coast, Nevada and Arizona markets. The viability of Recommendation 2 depends on the fuel preferences of load-serving entities outside the Rocky Mountain region.

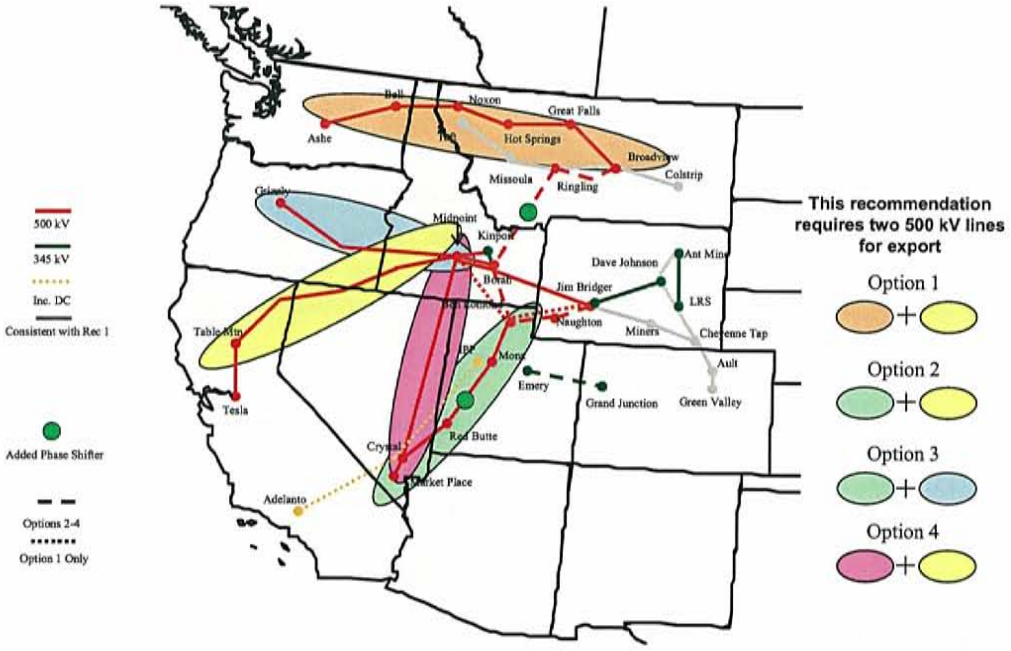
Recommendation 2 includes two of five optional 500 kV paths shown in the colored ovals in Figure E-2. Additional transmission upgrades in the Rocky Mountain region are also part of

Recommendation 2, including:

- Upgrading the Bridger Expansion project from 345 kV to 500 kV west of Bridger. Specifically, new 500 kV lines would be added between Bridger and Ben Lomond, Ben Lomond and Midpoint, Ben Lomond and Kinport, Borah and Midpoint, Borah and Ringling (including a phase shifter), and Ringling and Broadview;
- In lieu of a line from Broadview to Ringling to Borah, a 500 kV line from Broadview to Hot Springs may be considered; and,
- Adding new 345 kV lines between Grand Junction and Emery, Antelope and Laramie River Station, and Dave Johnson to Bridger.

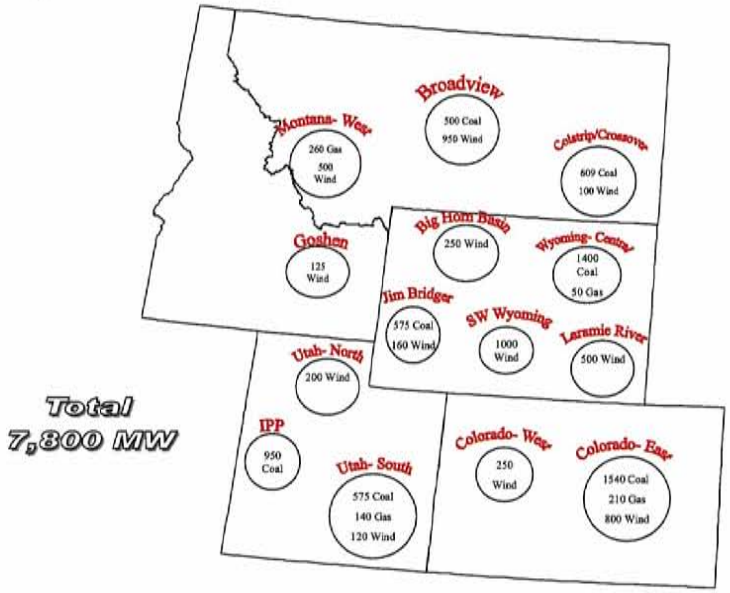
In addition, the existing IPP-Adelanto DC line would be upgraded. The capital cost for the Recommendation 2 transmission expansion is estimated to be $4,265 million.

*Figure E- 2: Transmission Expansion Extending Beyond the Rocky Mountain Region*




The economic analysis for these transmission export options was based on the assumed generation additions shown in Figure E-3.

*Figure E- 3: Generation Additions Assumed in Recommendation 2*




## Economic Analysis of Recommendations

To determine the benefits from transmission expansion, annual electricity production costs were simulated using the generation additions outlined above. The production costs were then added to the annualized capital and other fixed costs for the resource and transmission additions. These project cost totals were then compared with the project cost totals from two reference cases, an "all gas" case and an "IRP case"[2]. Table E-1 summarizes the annual savings from Recommendations 1 and 2 compared with the two reference cases.

*Table E- 1: Annual Savings Compared to Reference Cases*

*(Savings West-wide for Representative Year, Millions of Dollars)*

| | Reference Case | |
|---|---|---|
| | **All-Gas Case** | **IRP-Based Case** |
| | | |
| **Recommendation 1** | (531) | (61) |
| | | |
| **Recommendation 2** | (986) | (516) |

These estimated economic benefits are based on critical assumptions, including the future price of natural gas and hydroelectric conditions. These benefits assumed a 2013 gas price of $6.50/MMBtu ($5.20 in 2004 dollars). If natural gas prices drop and remain at $4.50 ($3.60 in 2004 dollars) over the long term, then the economic benefits of the Recommendations would be largely eliminated. However, if one assumes $6.50 gas prices and low hydro conditions over time, then the annual

[2] The All-Gas Reference Case assumes all load growth in the Western Interconnection is met by gas-fired generation. The IRP-based Reference (integrated resource plan) Case is grounded in the resource plans of PacifiCorp, Idaho Power and Xcel Energy and assumes all new generation outside the RMATS footprint is gas-fired.

production cost savings and the net benefit from constructing the projects in Recommendations 1 and 2 are significantly higher than shown in the table. Equally important, but not evaluated in the modeling, are the natural gas price hedging benefits of increasing access to coal and wind resources, through new transmissions. Strategies to hedge against volatile natural gas prices are important to provide greater stability in electricity prices.

Analyses were also performed to test the sensitivity of the findings to increased energy efficiency and potential constraints on carbon emissions. Increased energy efficiency could reduce or eliminate the need for new generation and transmission to meet load growth within the Rocky Mountain region. However, in that event, the transmission expansions in the Recommendation 2 would enable exports that reduce costs outside the Rocky Mountain region. A carbon adder of $15 per ton would not affect the dispatch of power plants that have been constructed by the time the adder is imposed. However, such a carbon constraint would affect the choice of new generation, an issue addressed in utility resource plans and not in this report.

Understanding where economic benefits will fall helps to identify likely project participants. The distribution of economic benefits from the projects in Recommendations 1 and 2 can be inferred from the modeling data, but not precisely calculated because the model diverges from current conditions by assuming perfect competition and locational marginal pricing. Figures E-4 and E-5 show the estimated distribution of annual economic gains based on fuel and other variables from Recommendations 1 and 2.

*Figure E- 4: Economic Benefits and Losses*

*(Annual Benefits in Millions of Dollars)*

*Recommendation 1 Compared to Reference Cases*

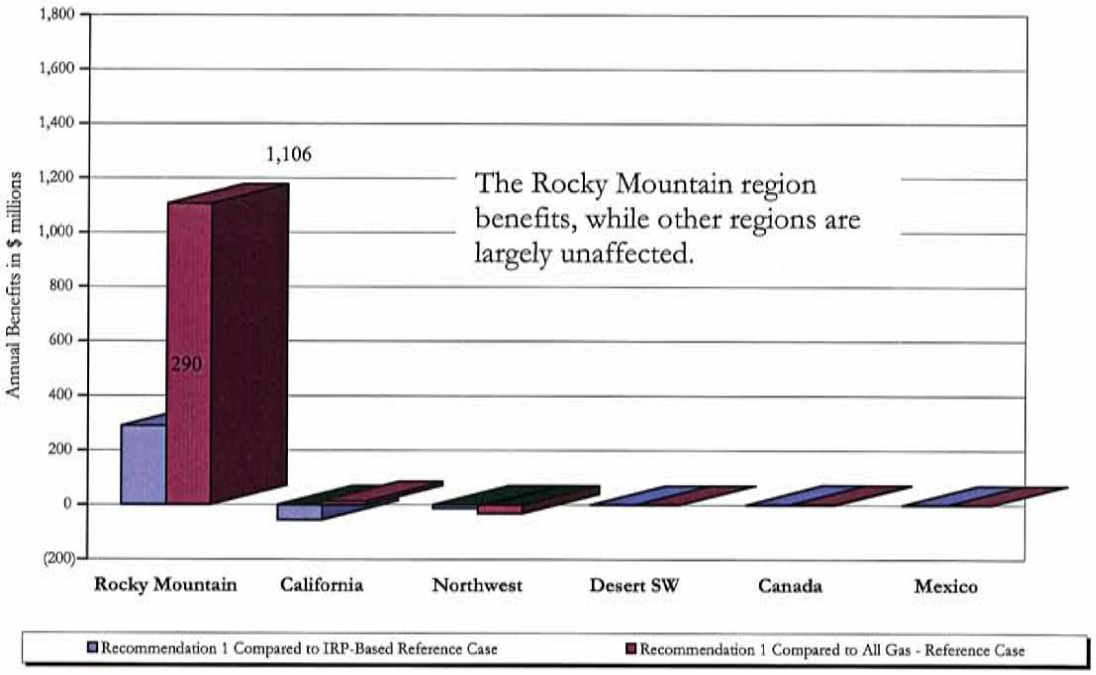
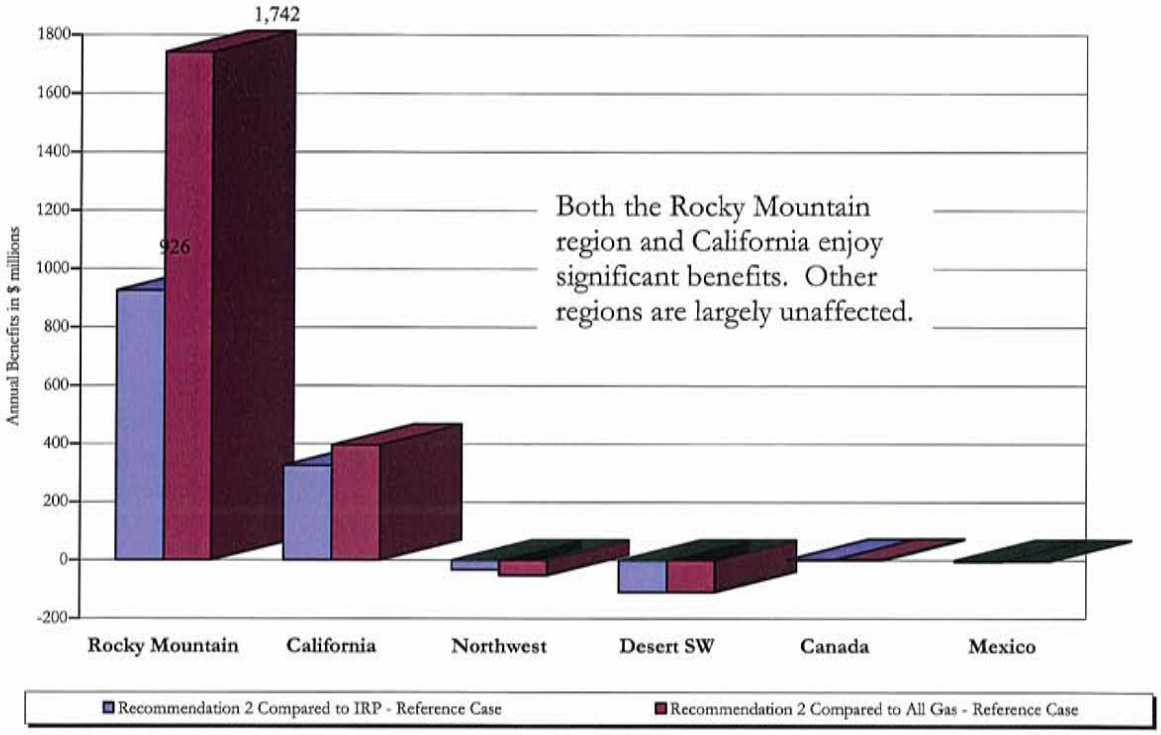


*Figure E- 5: Economic Benefits and Losses*
*(Annual Benefits in Millions of Dollars)*
*Recommendation 2 Compared to Reference Cases*




The distribution of economic gains associated with the three projects in Recommendation 1 fall predominantly within the Rocky Mountain region. This makes a compelling case for project beneficiaries to undertake needed technical studies and for entities in the Rocky Mountain region to work together to develop a cost allocation and cost recovery solution to capture this benefit.

Recommendation 2 entails exports from the Rocky Mountain region that would help the West diversify fuels and reduce opportunities to exercise market power by allowing new generators to develop projects that compete with incumbents.

With Recommendation 2, the annual consumer and generator benefits for the Rocky Mountain region increases to between $926 million to $1.7 billion. California consumers also stand to benefit from Recommendation 2, by $325 million to nearly $400 million annually. These results suggest that RMATS Phase II should coordinate work on Recommendation 2 with California's transmission planning institutions.

## Next Steps

As an initial step under Phase II, RMATS recommends, for each of the recommended transmission expansion projects, that the Governors of the states where the line would be sited convene a meeting of their public utility commissioners and the CEOs of entities that would benefit for the purpose of: (1) presenting the RMATS findings; (2) urging the beneficiaries to sponsor the projects;

(3) setting in place a process to address siting and cost allocation and recovery issues, (4) assessing financing issues; and, (5) initiating technical studies. The Governors should also consider inviting Governors and public utility commissioners from states outside the geographic scope of the transmission projects that would also benefit.

- For the Montana System Upgrade Project, RMATS recommends that the Governor of Montana convene a meeting of the CEOs of Northwestern Energy, the Bonneville Power Administration, the Montana Public Service Commission, coal and wind power plant developers in Montana, merchant transmission developers, and other potential project sponsors and participants.

- For the Bridger Expansion Project, RMATS recommends that the Governors of Idaho, Utah and Wyoming convene a meeting of the CEOs of Idaho Power, PacifiCorp, the Utah Associated Municipal Power Systems, the Utah Municipal Power Authority, the Wyoming Infrastructure Authority, coal and wind power plant developers in Wyoming, the Idaho Public Utilities Commission, the Utah Public Service Commission, the Wyoming Public Service Commission, merchant transmission developers, and other potential project sponsors and participants.

- For the Wyoming to Colorado Transmission Project, RMATS recommends that the Governors of Colorado and Wyoming convene a meeting of the CEOs of Xcel Energy, PacifiCorp, Black Hills Power, Basin Electric Power Cooperative, Tri-State G&T, the Western Area Power Administration, the City of Colorado Springs, the Platte River Power Authority, the Colorado Public Utilities Commission, the Wyoming Public Service Commission, the Wyoming Infrastructure Authority, coal and wind power plant developers in Wyoming and Colorado, merchant transmission developers, and other potential project sponsors and participants.

- For the export project options included in Recommendation 2, RMATS recommends that, depending on the option under consideration, the Governors of the affected states convene a meeting of the interested utilities, regulatory agencies and others. For example, if an option enhancing exports to California were being considered, we recommend that the Governors of Utah, Idaho and California convene a meeting including PacifiCorp, the Utah Association of Municipal Power Systems, California investor-owned and municipal utilities, the California ISO, the Utah Public Service Commission and the California Public Utility Commission. The Wyoming Infrastructure Authority should also be involved in meetings associated with Recommendation 2 projects.

Following such meetings, technical studies need to be conducted to examine the impact of the recommended projects on transmission system operations.

**Needed Institutional Improvements**

To improve the process of evaluating and financing transmission expansion and to operate the existing transmission system more efficiently, RMATS recommends that:

- Multi-State transmission expansion pricing principles be developed;

- The Wyoming Infrastructure Authority be engaged in transmission expansion financing discussions;
- The evaluation of transmission expansion to facilitate power exports from the Rocky Mountain region be integrated with regional planning in other parts of the Western Interconnection;
- Governors and regulators consider the formulation of a Regional Transmission Organization (RTO) with features appropriate to the region, including independence and cost-effectiveness; and
- The physical transfer capacity on existing lines be better utilized by requesting that transmission owners develop conditional firm or priority non-firm transmission products that quantify curtailment risks and place curtailment priority for conditional firm ahead of any non-firm transactions and curtailment priority for priority non-firm ahead of any non-firm transactions except secondary network resource service.

Further following specific actions are recommended:

1. To address cost allocation and recovery uncertainties, RMATS recommends that the state public utility commissions and energy agencies in the five states in the RMATS footprint deliver a report to their Governors in six months discussing multi-state transmission expansion cost recovery and pricing principles.

2. RMATS recommends that the regulatory commissions in Colorado, Idaho, Montana, Utah and Wyoming enter into a memorandum of agreement adopting pricing principles, and jointly file the MOA with FERC, requesting its endorsement. These principles would then apply to any applications for transmission cost recovery received by regulatory commissions within the Rocky Mountain region, providing a degree of certainty and consistency in regulatory treatment.

3. RMATS recommends that the RMATS Steering Committee, Load Forecasting Work Group, Resource Additions Work Group, Transmission Additions Work Group, and Cost Allocation/Cost Recovery Team be maintained and be available to conduct additional work as conditions warrant. An agreement among states and the electric power industry to maintain and finance a pro-active transmission planning process in the Rocky Mountain region is needed.
4. RMATS recommends that SSG-WI use RMATS export case analyses in the development of an interconnection-wide "realistic" generation scenario that would be studied in late 2004 and early 2005.

# Chapter 1 - Identifying Transmission Expansion Opportunities

## A. The Cost of Doing Nothing

If the transmission system is not expanded, the most likely generation alternative to meet load growth is to increase reliance on gas-fired generation located near load centers. Dependence on gas-fired generation may subject electricity consumers to substantial price volatility and high prices and leave load serving entities (LSEs) and their customers with limited generation options in the event high, volatile natural gas prices continue in the future.

The analyses presented in this Report suggest that well-considered transmission upgrades, capable of giving LSEs greater access to lower cost generation and enhancing fuel diversity, are cost-effective for consumers under a variety of reasonable assumptions about natural gas prices. This is important because ultimately the capital and operating costs of transmission and generation investments will be recovered from ratepayers.

What is the most prudent strategy to pursue in planning for adequate resources? The RMATS process demonstrates that a do-nothing transmission planning strategy comes at a cost. For example, the all-gas reference case discussed below shows that, if the West were to continue to rely on natural gas as the fuel for future generation additions, west-wide capital and variable operating and maintenance costs in 2013 will be approximately $530 million per year higher than they would be if Recommendation 1 were implemented and nearly $1 billion higher than if one of the export scenarios in Recommendation 2 were also built. Higher natural gas prices would further widen these gaps.

Since existing integrated resource planning processes are most often focused on a single state or a single LSE, the benefits of cooperative regional generation and transmission planning is not being fully realized. The RMATS analyses suggest that long-term coordinated resource and transmission planning on a region-wide basis can identify lower-cost resource options for consumers.

## B. Generic Benefits and Costs of Transmission Expansion

The benefits of investment in transmission expansion may include:

- Improved access for utilities to lower cost power.
- Increased ability of generators to diversify fuels used to serve their customers, which can help minimize fuel price risks and broaden access to renewable resources. Adding transmission and diversifying generation away from gas can reduced upward pressure on natural gas market prices.
- Greater liquidity and price competition in power markets, including mitigation of generator market power;
- Tax, revenue and other economic benefits to communities and states where development takes place; and
- Improved reliability and greater flexibility for maintenance and other operational purposes.

The cost of new transmission includes the capital cost of building the line, equipment, and other facility operating and maintenance costs over the life of the assets, environmental impacts from

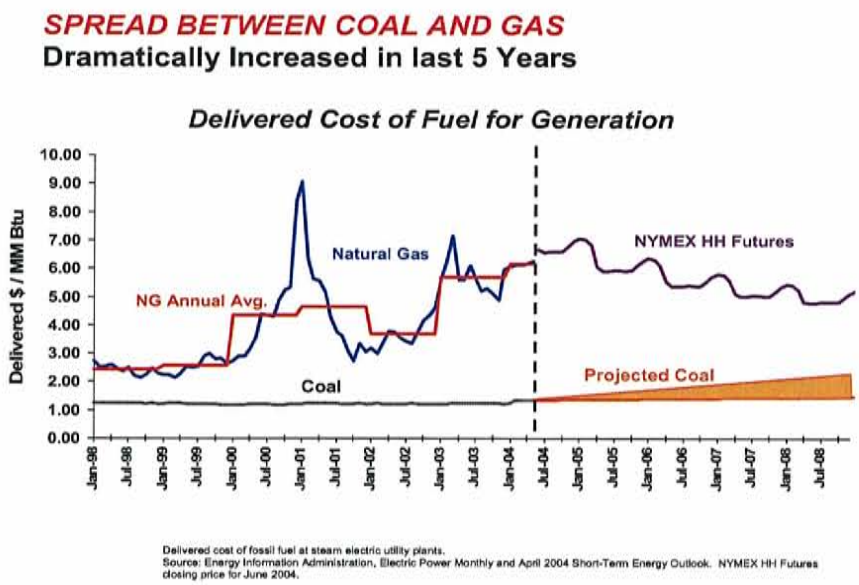
construction of lines, and changes in property values resulting from the location of lines. Although it is commonly assumed that property values decline in the vicinity of a transmission line, they could increase, particularly for industrial properties and wind farm sites benefiting from better access to transmission lines.

**Discussion of Types of Benefits and Beneficiaries**[1]

**Lower Cost Generation:** Benefits of accessing lower cost generation flow to utilities and their customers and to certain generators. Figure 1-1 shows the fuel price differentials between natural gas and coal. There is no fuel cost associated with wind generation.

Implementation of the RMATS recommendations would enable greater use of coal and wind resources and significant reductions in fuel costs and other variable operating and maintenance costs on a West-wide basis. This new access to lower cost generation can also reduce net revenues for some existing generators, whose higher cost generation may be displaced.

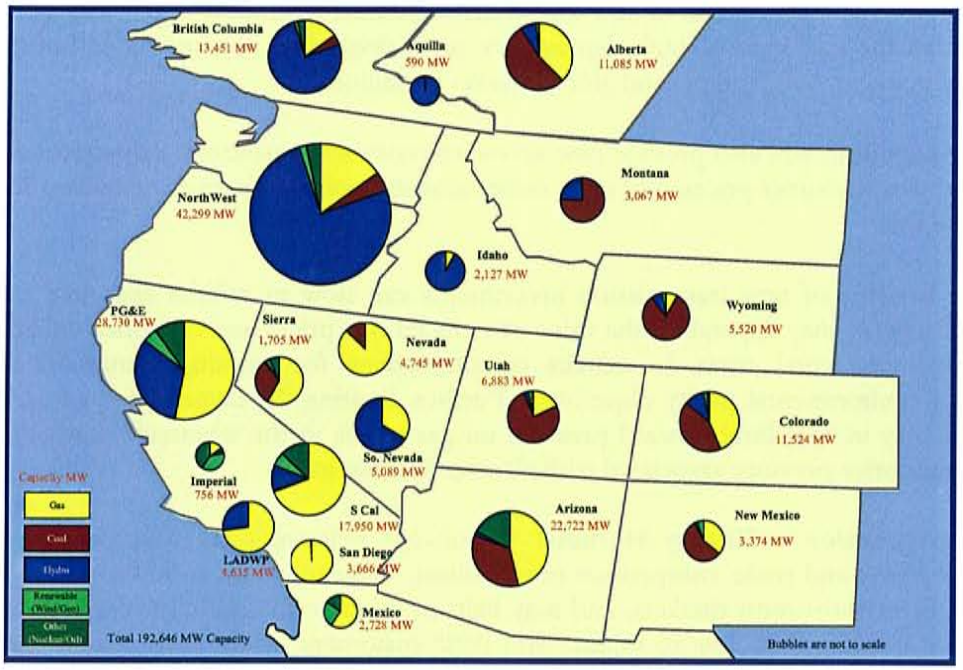
*Figure 1- 1: Natural Gas and Coal Fuel Prices*




**Fuel Diversity:** Figure 1-2 shows the current generation mix in the Western Interconnection.

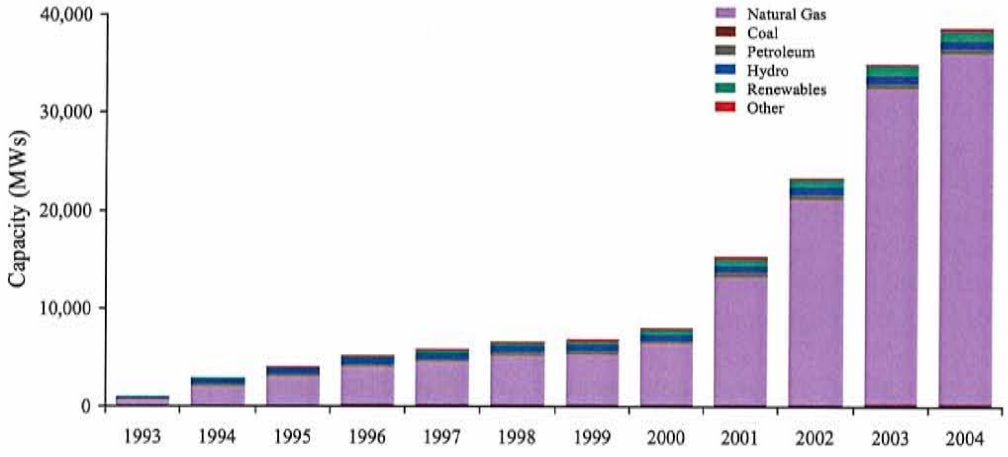
[1] Presumably under FERC Order 888, the benefit of owning transmission to block competitors having access to one's power markets has been eliminated. However, there still may be benefit to the integrated utility in owning the line since the utility will calculate and reserve Available Transmission Capacity on the line for future load growth, thereby providing an advantage over other users of the line.

*Figure 1- 2: 2008 forecasted generating resource capacity in the Western Interconnection by fuel type*




The interconnection is becoming increasingly dependent on gas-fired generation. Figure 1-3 shows the cumulative generating capacity additions by fuel type in the Western Interconnection over the last ten years. More than 90% of the interconnection is becoming increasingly dependent on gas-fired generation. As a result, natural gas sets the price of electricity in the Western states more than 70% of the time. Figure 1-3 shows that gas-fired generation is often the marginal fuel in the West.

*Figure 1- 3: Gas-fired generation accounts for 92% of new capacity over the last 10 years*




Western Interconnection Cumulative Generating Capacity Additions by Fuel Type (1993-2004)
Source: EEI

By diversifying fuels, generators can mitigate gas price risks[2]. Added transmission capacity acts as a "hedge" against the risk of upward swings in the forward price of power from natural gas and any other fuel source. The construction of new transmission permits customers to pay a known quantity now to diminish the risk later of high dependency on a single fuel source whose future price is vulnerable to fluctuations in regional and global market conditions.

Transmission expansion will also provide new access to renewable resources, helping to reduce fuel price risks, stabilize customer prices, and meet environmental policy objectives, including Renewable Portfolio Standards.

Fuel diversity benefits of new transmission investments can flow to utilities and their customers. The extent of benefits may depend on the value of reduced fuel prices and fuel price volatility to the generator, the incremental costs to utilities of alternatives for meeting Renewable Portfolio Standards, and environmental policy objectives. Further, limiting the demand for natural gas as a generator fuel may in turn limit upward pressure on gas prices in the wholesale market, including seasonal summer price pressure associated with air conditioning loads.

**Enhanced Competition in Energy Markets:** In concept, relieving congestion in energy markets will increase liquidity and make competition more robust. This may lead to lower and more stable prices, especially in short-term markets, and may help to mitigate the exercise of generator market power, creating benefits that flow to utilities and their customers within and outside the RMATS region.

**Local and State Economic Development:** Construction of new power plants provides economic development benefits in terms of jobs and increased tax revenues to the communities and states hosting the plants. Tax revenue benefits for states and localities include increased property taxes, additional franchise and other tax revenues, and increased state and local income taxes, along with secondary and tertiary induced and indirect economic benefits and resulting taxes flowing from the investments. Offsets include increases in utility rates due to higher revenue requirements.

**Reliability:** All new transmission investments must meet the goal of maintaining or improving reliability and must meet WECC reliability standards. New transmission investment can provide reliability benefits, reduce line losses, allow more efficient maintenance of the system, and enable the use of new technology to provide better information flows and control potential for existing lines, thereby giving system operators more tools to manage the transmission system and address unforeseen problems. New long distance lines may increase reliability beyond that required by WECC, particularly if they have capacity beyond that needed to meet expected loads. These reliability benefits may disappear over time if new flows consume excess transfer capacity. The economic value of reliability investments can be quantified by determining the value of a reduced likelihood of forced outages or diminished service, but are not part of this study.

Quantifying transmission investment benefits and identifying beneficiaries are challenges and matters of judgment. Where construction of a new transmission line is linked to the construction of

[2] The level of future natural gas prices and the volatility of gas prices represent a principle factor in the choice of future generating resources. Recent high prices and extreme price volatility have accentuated concerns about over-reliance on gas-fired generation to meet future electricity demand. Prices and price volatility may be mitigated should LNG be imported to North American on a large scale. Large scale LNG imports, however, raise other energy security issues.

specific power plants, there is greater ability to identify the benefits from fuel diversification and reduced costs to load serving entities. One can also identify the generators that benefit from the new line.

Where additional transmission investment is not linked to construction of specific power plants, it is more difficult to determine the extent to which additional investment will provide fuel diversity benefits and lower power costs to consumers since the types of generation built and the cost of power will be determined by market forces. It would also be more difficult to recover part of the investment from generators in advance of construction. If new lines are built and generators secure transmission service over the lines, revenues charged for use of the lines can offset construction costs.

Benefits of new transmission investment can accrue to:

- Load serving entities and their customers,
- New generators who can now reach markets,
- Existing generators who can reach new markets,
- Communities and states where development occurs, and
- All transmission system users where the transmission investment improves system-wide reliability.

## C. Background and History of the RMATS Effort

The modern era in transmission planning in the Western Interconnection began in August 2001 with the release by the Western Governors' Association of a report entitled Conceptual Plans for Electricity Transmission in the West. The report, which was developed in the wake of an electricity crisis that affected prices and supply and held the West in its grip for many months, revealed that new transmission and generation infrastructure located remotely from population centers could produce benefits for consumers throughout the West. This investment strategy was shown to be an effective means of ensuring that growing electricity demands are met with a diverse portfolio of resource options, including renewables and coal, to keep the West from putting excessive dependence on new natural gas-fired generation. The study was conceptual and did not identify specific projects or undertake the detailed work necessary to establish financial viability, obtain approvals, or to site and construct transmission facilities.

In 2001, Western Governors asked the Seams Steering Group-Western Interconnection (SSG-WI) to develop an ongoing proactive transmission planning process for the interconnection. In 2003, SSG-WI released its first report on transmission needs on the west-wide interconnection. The report examined three bookend generation scenarios and necessary transmission. The SSG-WI study effort developed a public database to support transmission expansion analysis. Although the SSG-WI report refined the analysis in the WGA report, it did not provide sufficient detail to enable the development of specific transmission projects. Detailed sub-regional studies are therefore necessary to evaluate specific transmission proposals.

On August 22, 2003, Wyoming Governor Dave Freudenthal and Utah Governor Michael Leavitt announced the formation of the Rocky Mountain Area Transmission Study (RMATS). The Governors found that: "For many years, utilities and other entities have been reluctant to make investments in needed electric transmission infrastructure. This has been due to a number of factors, including protracted uncertainties in the regulatory environment and nascent regional

transmission organizations under development. As a consequence of this lack of transmission expansion, transmission congestion and bottlenecks are increasing. While this is a problem throughout the western interconnect, it is becoming an acute issue in areas of the Rocky Mountain sub region." The Governors directed that a charter be developed for the study that specified goals, principles and operating procedures. The study covers several western states including Colorado, Idaho, Montana, Utah and Wyoming.

In addition to the RMATS effort, there are three other sub-regional transmission planning processes under way in the Western interconnection. The Central Arizona Transmission Study (CATS) (now expanded to include New Mexico and parts of Colorado and Nevada and renamed the Southwest Area Transmission (SWAT) Planning Committee) was the first sub-regional transmission planning process. As a result of the CATS process, transmission projects were identified and at least one is under construction. The Southwest Transmission Expansion Plan (STEP) is examining transmission needs in the Arizona-Southern California-Southern Nevada region. STEP is using the same model and public database used in the SSG-WI process. Finally, the Northwest Transmission Advisory Committee (NTAC) is beginning an effort to examine transmission expansion needs in the Pacific Northwest region. There are also state-specific transmission planning efforts underway, such as the Montana Transmission Advisory Group (MTAG) which was created in March 2004 to bring together the stakeholders within Montana to address transmission issues, including exports from Montana, and to begin to develop action plans to overcome those obstacles.

In response to the directions of Governors Freudenthal and Leavitt, a white paper and draft charter were developed in preparation for the September 26, 2003, kickoff meeting of stakeholders in the RMATS process. Based on stakeholder input received at that meeting, the RMATS Steering Committee adopted a charter on October 14, 2003.

**RMATS Charter (excerpts)**

**PART 1. Goals**

a. Secure and commit the resources to the planning process needed to make it a success.
b. Identify technically, financially and environmentally viable generation projects with potential for development in the Rocky Mountain Region in the near future.
c. Identify necessary transmission infrastructure to support such development.
d. Evaluate needs, alternatives, costs and benefits of generation and transmission within the Rocky Mountain states.
e. Identify probable obstacles to the siting and construction of potential transmission projects.
f. Identify necessary financial and technical resources to enhance the successful development of needed transmission.
g. Develop necessary information to facilitate regulatory approvals of new transmission.

**PART 2. Principles**

a. Include all interested stakeholder individuals and groups in the Rocky Mountain Area Transmission Study.
b. Work together for effective solutions in a balanced, open and inclusive public process.
c. Conduct analysis of generation and transmission alternatives based on data, assumptions, and scenarios developed by participating stakeholders.

d. Consider every need, generation technology and location option that is appropriate for the Rocky Mountain States.
e. Evaluate all potential transmission alternatives within the Rocky Mountain region.
f. Identify the costs and benefits of generation and transmission options for serving electricity needs of consumers that make operational, economic, and environmental sense for the Rocky Mountain states.
g. Cooperate and coordinate with the region-wide SSG-WI planning effort and other regional planning efforts.
h. Cooperate and coordinate with WECC in order to ensure maintaining or improving system reliability.

**PART 3. Operating Procedures**

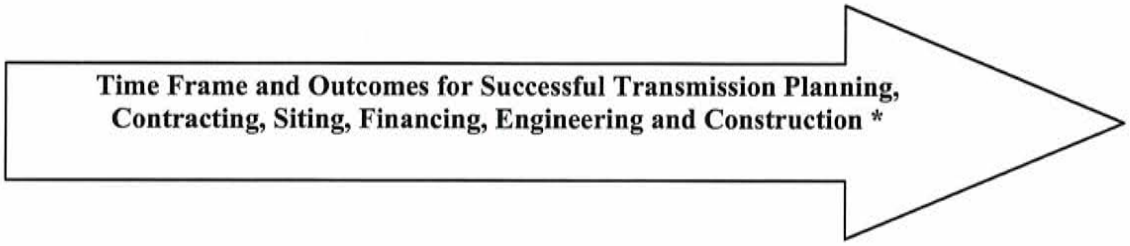
a. The Rocky Mountain Area Transmission Study (RMATS) will be informed and guided by the Enlibra Principles adopted by the Western Governors' Association.
b. The Study will be a front-end planning process that will evaluate needs, alternatives, costs and benefits of generation and transmission within the Rocky Mountain states.
c. The Study will be facilitated by an independent third party facilitator.
d. Three stakeholder meetings will be held to help develop and implement the Study.
e. A Steering Committee will be formed at the kick-off meeting to direct the Study and, as necessary, approve modeling assumptions.
f. Working Groups will be formed at the kick-off meeting to carry out the work of the planning process. Initial expectations are that a Resource Additions Workgroup, a Transmission Additions Workgroup, a Load Forecasting Workgroup and a Report Writing Workgroup will be established.
g. PacifiCorp will perform the technical studies based on assumptions and scenarios developed by participating stakeholders, and provide an in-kind contribution of resources to perform this work.

The planning initiative is the first step of a multiphase process necessary for successful transmission expansion in the Rocky Mountain region. In Phase I, representative generation is identified and specific transmission projects to support such generation are examined and analyzed. Phase I will produce:

- An in-depth understanding of the impacts on system-wide production costs of specific transmission investments in the Rocky Mountain states;
- An assessment of needed regulatory approvals and financial backing for the projects and identification of obstacles to moving forward; and,
- The foundation for future work on siting, obtaining regulatory approvals, contracting, financing, engineering and construction of projects where appropriate (i.e., Phases II and III).

Phase I is intended to provide enough information to interested stakeholders for their further analysis to determine if there is economic interest in pursuing project development. Phase II and Phase III will occur as project sponsors decide to move forward with projects. Figure 1-4 below illustrates the basic elements of the process.

*Figure 1- 4: Phases of RMATS Work*




| **Phase I – Planning and Project(s) Definition** | **Phase II – Regulatory Approvals, Contracting, Siting, and Financing** | **Phase III – Engineering and Construction** |
|---|---|---|
| **Time Frame:**<br>September 2003 – September 2004 | **Time Frame:**<br>To be determined by Project Sponsors | **Time Frame:**<br>To be determined by Project Sponsors |
| **Outcomes:**<br>• Specific transmission projects are defined to support resource additions as proposed, including renewables and thermal plants<br>• Impacts of transmission and generation additions are derived, including: generation capacity utilization; path loading duration curves; congestion and power flow implications; and where and how consumers benefit<br>• Indications of interest in subscribing to and financial support for specific projects<br>• Identification of any barriers to project advancement<br>• Development of information necessary to pursue regulatory approvals<br>• Study results incorporated in West-wide transmission studies, including SSG-WI | **Outcomes:**<br>• Siting and permitting of specific selected transmission and generation projects<br>• Where appropriate, sponsoring Governors initiate the State/Federal siting protocol collaboration<br>• Subscription, contracting and financial arrangements put in place on specific projects<br>• Barriers to project advancement are removed, where possible, including Governors' initiative, if necessary | **Outcomes:**<br>• Engineering design and construction of selected projects, subsequent to successful siting, approval and permitting, and removal of any identified obstacles |

- Emphasis shifts from the RMATS Planning Effort to project developers when reading from left to right across the Table.

### The RMATS Process

An open stakeholder process is the guiding element of the RMATS effort. The September 26, 2003 kickoff meeting was attended by over 150 stakeholders. As a result of this meeting, four working groups (a Load Forecasting Work Group (LFWG), Resource Additions Work Group (RAWG), Transmission Additions Work Group (TAWG), Report Writing Work Group (RWWG)), two work teams (the Cost Allocation and Cost Recovery Team (CACRT) and a Modeling Team), and a Steering Committee were established. Stakeholders populated the working groups and Steering Committee, and PacifiCorp assembled the Modeling Team. As work proceeded, a Regulatory and Operational issues Work Group was created to address transmission reforms that would enable greater use of the transmission system by wind generation. New work group and team members were accepted freely as persons expressed interest in the RMATS process.

The Work Groups and Steering Committee met frequently in conference calls and in person; and all meetings were open to interested parties. Written summaries of the Steering Committee meetings were prepared and have been posted on the RMATS website at http://psc.state.wy.us/htdocs/subregional/steering.htm.

Figure 1-5 shows the chronology of the RMATS Phase I study effort.

*Figure 1- 5: Chronology of RMATS Phase I Activities*

| | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Stakeholder meetings | | | | | | | | | | | | | |
| Steering Committee | | | | | | | | | | | | | |
| LFWG | | | | | | | | | | | | | |
| RAWG | | | | | | | | | | | | | |
| TAWG | | | | | | | | | | | | | |
| RWWG | | | | | | | | | | | | | |
| CACRT | | | | | | | | | | | | | |

The principal effort of the RMATS work groups and Steering Committee for most of this period focused on the modeling endeavor described in the following chapter.

# APPENDIX A-5-F

# Chapter 2 -Transmission Study Approach

## A. Introduction

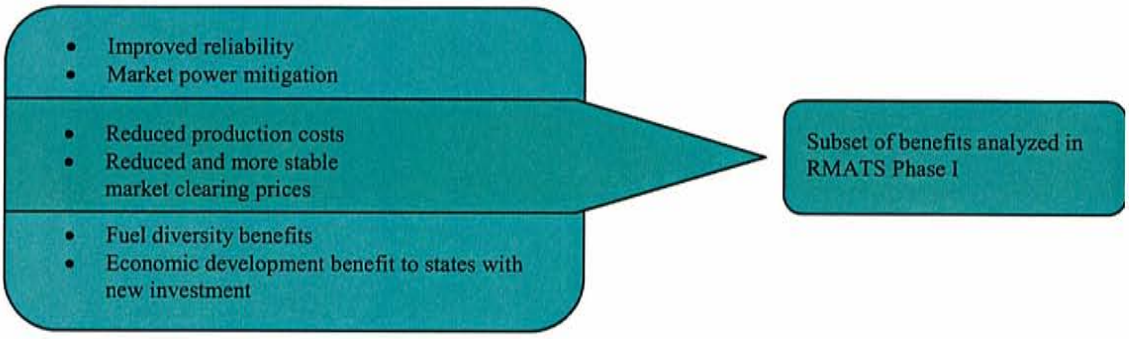
In RMATS Phase I, the focus has been on determining the economic implications of transmission expansion alternatives for the Rocky Mountain states and for the West. From this economic screening work, two recommendations emerged that could provide substantial benefits through expansion of the transmission grid. The recommendations are described in detail in Chapter 3.

Phase I included these analytical steps:

- Forecast load growth.
- Develop generating resource scenarios.
- Identify areas of transmission congestion and quantify the costs of that congestion.
- Develop transmission expansion solutions to relieve congestion and support new resources.
- Quantify the savings in production costs as congestion is relieved through the resource and transmission expansion scenarios.
- Quantify the fixed costs of the scenarios.
- Compare the incremental costs and net savings of the scenarios.
- Estimate whether loads (consumers) and generators may gain or lose economically in the various regions of the West.

The benefits analyzed in RMATS Phase I are a subset of the potential benefits of transmission expansion. (See Figure 2-1.) In addition to the production costs, market price benefits, and natural gas price sensitivities that this study measures, transmission expansions can also provide additional fuel diversity benefits, improve reliability, reduce generator market power, and provide additional tax revenue and other economic benefits to states.

*Figure 2- 1: Potential Benefits of New Transmission Investment*




The study sequence began with a base case that identified areas of transmission congestion and quantified the costs of congestion in the existing transmission system. This base case was prepared with a production cost model that included a detailed representation of the Western Interconnection.

The Work Groups[1] created four scenarios with resource additions, each with an eye to meeting longer-term load growth. Transmission facilities were then added to reduce congestion and lower production costs. Production costs (largely variable fuel costs) were simulated for these resource and transmission alternatives, as were capital investment requirements and annualized fixed costs. Several sensitivity analyses were also performed; including natural gas and coal fuel price, hydro condition, demand-side management measures (DSM) and carbon adder sensitivities. Costs were then totaled and compared to identify the lower-cost alternatives. Finally, economic gains and losses were estimated for consumers (loads) and generators in the Rocky Mountain states and elsewhere in the West.

From these analyses, the RMATS Steering Committee formulated two recommendations for transmission expansion that are discussed in detail in Chapter 3. The recommendations will undergo technical study, siting review, financial planning, and further economic analysis in RMATS Phase II.

## B. Overall Approach

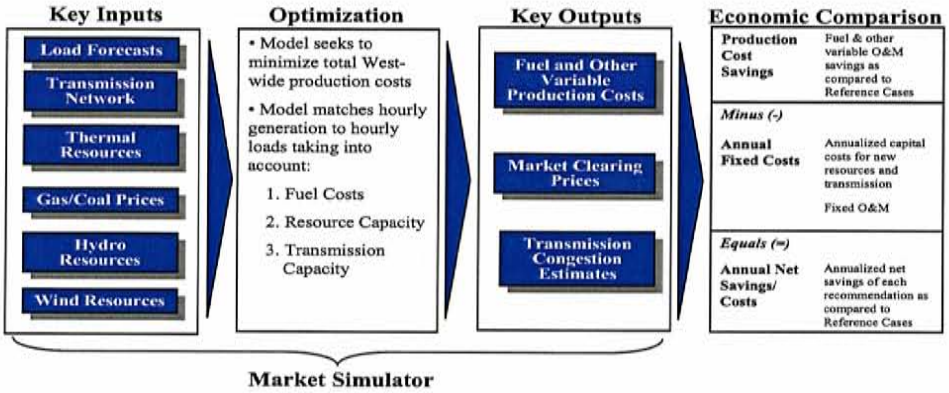
System operations and production costs are simulated for the Western Interconnection, with a spotlight placed on resource and transmission alternatives in the Rocky Mountain states. Key assumptions were developed by consensus of the Work Groups, including forecasts for loads, natural gas and coal fuel prices, wind generation, transmission capacity, and potential carbon constraints. The West-wide transmission planning study conducted by SSG-WI in 2003 was the starting point for these assumptions.

Two test years were used. The first test year is the 2008 base case, which was used to identify the incidence and duration of congestion in the current system and to calibrate against historical flows. The base case represents the existing generating resources and transmission system, as well as new resource and transmission additions that are expected to be operational by 2008.

The second test year, 2013, reflects growing loads and generation and transmission expansion scenarios developed by the Work Groups. The year 2013 is used to provide a reasonable lead-time for construction of any major transmission expansions and coal plants. The study quantifies and compares production costs and fixed costs of the scenarios for purposes of arriving at economically viable project recommendations. Figure 2-2 is a flow diagram of the process involved in the RMATS analysis.

[1] See Chapter 1 for discussion of the RMATS process, including the establishment and use of several Technical groups.

*Figure 2- 2: RMATS Analysis Process*




## Production Costs

ABB Market Simulator is the production cost model used to simulate transmission congestion, marginal prices at the nodal (bus) level, and system-wide fuel and other variable production costs.

Market Simulator is designed to produce:

- Congestion estimates – demonstration of when and where transmission bottlenecks occur.
- Market clearing prices – estimates of marginal prices that vary by location (bus or node) (LMPs), including spot energy curves and shadow transmission prices.
- Generating resource dispatch – simulation of the lowest cost dispatch for the Western Interconnection.
- Transmission expansion – the production cost effects of proposed transmission additions.

Market Simulator seeks to minimize system production costs while dispatching hourly generation to meet hourly loads. This optimization takes into account gas and coal fuel prices, resource capacity constraints, energy constraints (hydro and wind resources), heat rates for thermal plants, planned outages, minimum generator up and down times, and physical (not contractual) transmission constraints.

The amount of load, resource, and transmission data required to simulate West-wide system operations on an hourly basis at the nodal level is large. To keep the analysis efficient and flexible, certain simplifying assumptions regarding dispatch parameters and data are necessary. For example, the simulation assumes a single, seamless West-wide market, with none of today's inefficiencies due to multiple control areas and rate and loss charge pancaking. (These simplifying assumptions are consistent with an RTO world, i.e. no rate or loss charge pancaking and consolidation of control areas.) It also assumes an optimal West-wide dispatch of generating resources. Hydroelectric and wind resource generation are determined outside the model and then entered as fixed inputs around which thermal resource dispatch is simulated. Neither parameters for "must run" generation and unit commitment nor strategic bidding behaviors are included.

The simulation differs from real-world decision-making. In both cases, the location of new generation drives the need for new transmission. In the RMATS simulation, the location of new generation is an assumed input. Among the four 2013 scenarios modeled, only one is linked to available resource plans of three load serving entities in the RMATS footprint (PacifiCorp, Xcel Energy, Idaho Power Company). In the real world process, the decisions on building new generation are largely determined by choices made by load serving entities and their regulators. A significant shortcoming is that each load serving entity makes decisions in relative isolation. Because transmission additions and some generation additions (e.g., coal) tend to be developed in lumpy increments (i.e., do not come in capacity additions sized to meet incremental needs) and because there tend to be economies of scale in building transmission (a 500 kV line does not cost twice as much as a 230 kV line), a transmission addition may not be economic for a single load serving entity, but would be economic when combined with the needs of others.

In the RMATS simulation, once the location and type of generation and transmission additions have been chosen, the dispatch of existing and new generation is based on the lowest fuel costs -- without regard to plant ownership or contracts. In the real world, decisions on which generation resource to dispatch are typically made by each owner based on the relative operating costs of its particular units and contractual obligations.

In the RMATS simulation, the transfer of electricity from the generator to the load is constrained only by the physical capabilities of the transmission system. Contractual constraints are not included. The RMATS simulation reflects a flow-based, financial rights world. In other words, the simulation already includes the benefits of moving to a regionally operated system that removes institutional impediments to a more optimal use of existing assets. In actual practice, moving power from a generator to a load occurs under schedules over specified transmission paths or network service contracts. To execute a schedule, a party must have rights to use specific transmission paths from the generator to the load. Today, transmission capacity is often deemed to be unavailable even when lines are not physically fully loaded.

In the RMATS simulation, dispatch is "optimized" on a West-wide basis, meaning that production costs are minimized for the Western Interconnection as a whole. Where congestion causes significant differences in costs between areas, transmission additions are formulated to enable power to flow from locations with lower operating costs to areas with higher operating costs. In today's world, a market participant examines whether new transmission would lower the cost of acquiring generating resources to meet the demands of its customers.

See Appendix B.2 for details on the logic, inputs, outputs, and limitations of ABB Market Simulator.

### Capital and Other Fixed Costs

Capital investment requirements and annualized fixed costs are determined for each resource and transmission scenario. Resource capital investment requirements are based on the development and construction cost estimates by resource category from the Northwest Power and Conservation Council's (NWP&CC) Draft *New Resource Characterization for the Fifth Power Plan* reports and a California Energy Commission report on renewable resources. In these studies, the capital investment amounts for new gas-
fired resources do not include the investment that may be required for pipeline compression and expansion. Transmission costs are estimated on a line-by-line basis using historical data and the

professional judgment of Work Group members.

Annualized fixed costs include resource and transmission capital charges associated with the investment and fixed operational and maintenance expense (O&M),. The production (fuel and other variable O&M) costs and the annualized fixed costs associated with each scenario are then totaled and the scenarios are compared to estimate relative costs or savings.

## C. Key Data Assumptions

As a starting point, RMATS used the data base for Western Interconnection loads, resources, and transmission that SSG-WI had compiled through an extensive coordination process in 2003. Updates and corrections to these data were made by the Work Groups. The key assumptions are summarized here, with an expanded discussion included in Appendix B.1 .

### Transmission Topology

For this study, the Western Interconnect transmission system (topology) includes 33 bubbles or sub-areas (as shown in Figure 2-3). The system is split into bubbles to disaggregate monthly load peaks and energy, to identify transfer links (transmission interfaces), and to summarize study results. The starting point for the RMATS topology was the WECC 22-bubble topology. Six SSG-WI bubbles were disaggregated, adding eleven bubbles to the WECC topology to increase the data granularity for the Rocky Mountain area. Figure 2-4 displays the regional aggregation used for the RMATS studies. This aggregation is used for presenting regional gains and losses analysis in Chapter 3 as well as for displaying the load levels used for the 2013 studies.

*Figure 2- 3: Transmission System Topology*

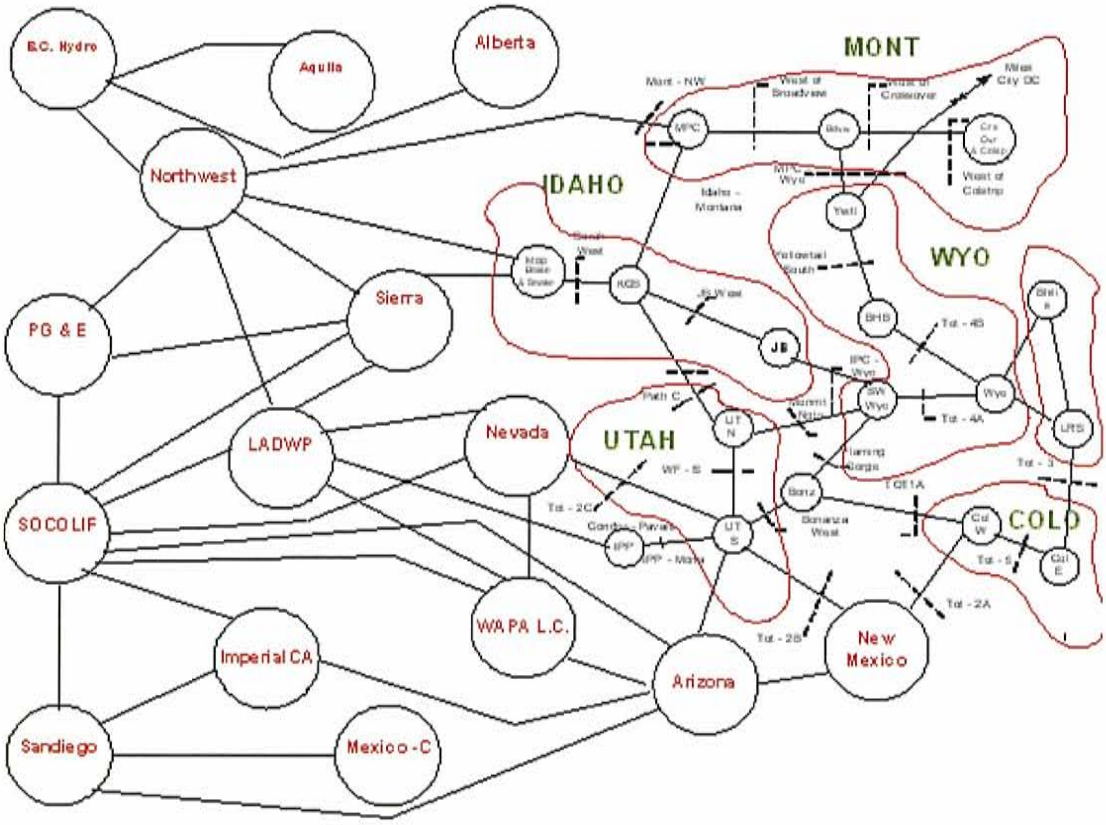
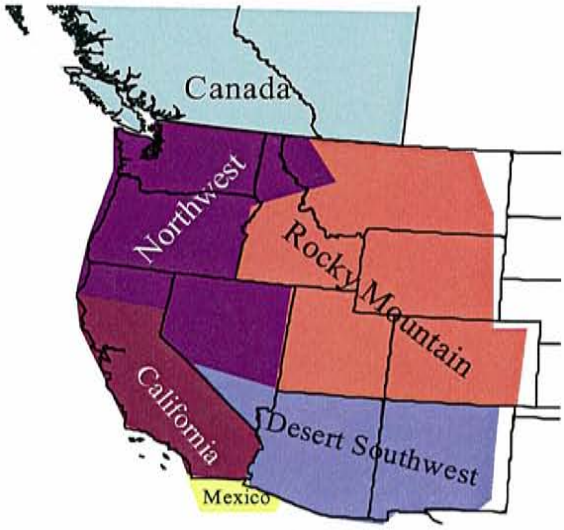



*Figure 2- 4: RMATS Regional Aggregation*



### Transmission Path Ratings and Nomograms

The study applied the path and nomogram[2] ratings posted in the WECC February 2003 Path Rating Catalog. Paths and nomograms internal to companies were added and rated by the Transmission Additions Work Group (TAWG).

Path ratings are "Maximum Path Transfer Capabilities" based on WECC path rating methodology. Most of the ratings reflect capabilities based on technical limits determined from system studies. It does not represent Available Transmission Capacity because it does not indicate the degree to which the path transfer capability has been committed pursuant to provisions of open access transmission tariffs under FERC Order 888.

### Powerflow Case

The WECC 2008 LSP1-SA (light load-spring) approved power flow case was the starting point for all analyses. The ABB Market Simulator model, which uses a DC approximation power flow, modeled the system for this study.

### Electricity Demand (i.e., "Loads")

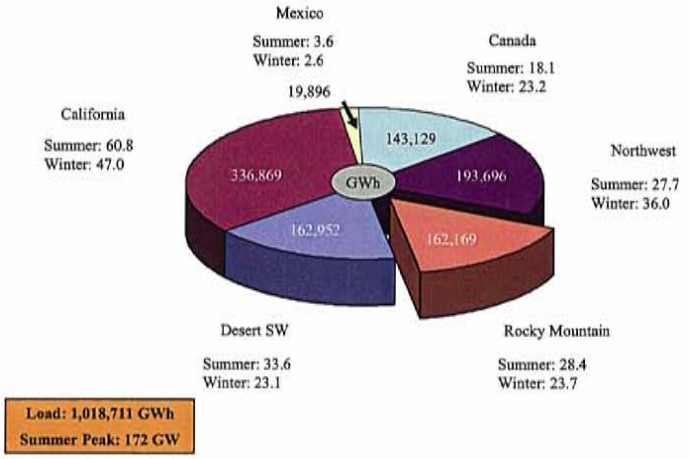
Loads were based on the WECC load forecast issued in the Spring of 2003. The Load Forecasting Work Group (LFWG) made certain updates and corrections. For the Rocky Mountain region, the LFWG collected monthly peak and energy numbers for the eleven new bubbles, determined the appropriate load growth factor for each, and developed forecasts for test years 2008 and 2013. For areas outside of the Rocky Mountain region, the SSG-WI load forecast was modified by applying loads from the WECC 2003 Loads and Resources Report.

The WECC-based forecast was at a more aggregate level than needed to calculate LMPs. To determine hourly demand for each node of the transmission system, load distribution factors from the WECC power flow case were fitted onto the load shapes in the WECC-based load forecast.

Figure 2-5 displays the load levels used for the 2013 studies. It includes the annual energy values as well as summer and winter regional peaks. The Rocky Mountain region represents approximately 16% of the total energy load in the West.

[2] Nomograms here define the relationship between generation, load, voltage or system stability in a defined network.

*Figure 2- 5: Annual Energy (GWh) with Coincidental Summer and Winter Peaks (GW)*




## Natural Gas Prices

For the 2008 Base Case, the U.S. average wellhead price is $4.00/MMBtu in 2008 dollars ($3.60 in 2004 dollars) for the low gas price sensitivity, and $5.00/MMBtu ($4.50 in 2004 dollars) for the high gas price forecast. This range is consistent with the December 2003 forecast prepared by the Energy Information Administration. Differentials were included for various locations consistent with the Fifth Northwest Conservation and Electric Power Plan.

For the 2013 study, prices use were $4.50/MMBtu in 2013 dollars ($3.60 in 2004dollars) and $6.50/MMBtu ($5.20 in 2004 dollars), respectively (based on the most current Energy Information Administration forecast, dated December 2003). The Resource Additions Work Group (RAWG) deems these prices to represent a reasonable range of likely outcomes.

## Coal Prices

Coal prices are from the Northwest Power Planning Council's "New Resource Characterization for the Fifth Power Plan" (February 2004). Prices are modified at various locations to account for rail or truck transportation. RAWG forecasts that coal will escalate at a rate of 1.5% per year from the 2004 prices shown in Table 2-1.

*Table 2- 1: Annual Energy (GWh) with Coincidental Summer and Winter Peaks (GW)*

| | Dollars (2004) per MMBTU |
|---|---|
| WY/MT Powder River mine mouth | $0.40 |
| WY/MT Powder River transport WY/MT | $0.60 |
| WY/MT Powder River transport to CO | $0.70 |
| MT/ND lignite | $0.55 |
| UT trucked coal | $0.90 |
| UT rail transport | $1.25 |
| SW WY mine mouth | $1.00 |

### Existing Thermal Plants

Thermal plant assumptions rely on the SSG-WI data base. All existing plants are assumed to remain in operation, except plants due to retire as outlined by the California Energy Commission. The Mohave power plant is assumed to retire at the end of 2005 (a sensitivity case is conducted for 2013 that assumes this resource is not retired).

Starting assumptions for maintenance outages are from the SSG-WI study, which in turn drew from the Tabors-Caramanis Cost-Benefit Analysis for Grid West. Refinements were made to these assumptions to more accurately reflect the outage coordination that occurs within areas. Outage levels in each area were reviewed to ensure they comport with these rates:

*Table 2- 2: Typical Plant Outage Rates*

| Plant Type | Outage Rate |
|---|---|
| Combined Cycle | 7% |
| CT | 7% |
| Coal Plant | 10% |
| Steam Oil/Gas | 10% |
| Nuclear | 12% |
| Geothermal | 10% |

Heat rates are assumed to be the same for plants of the same vintage, type and class.

### Hydroelectric Resources

All hydro plants currently in operation are assumed to remain in operation. As noted, hydro dispatch is a fixed input determined outside of the Market Simulator. Average hydro conditions were assumed in the analyses. Sensitivities were conducted for low and high hydro conditions. See Chapter 3 and Appendix B.7 "Sensitivities" for additional detail.

### Wind Resources

Renewable resources in the 2008 Base Case are the same as those used in the SSG-WI study, with the addition of the Pleasant Valley wind farm (144 MW) and some additional wind capacity in Colorado (23 MW). For the 2013 studies, new wind resources are analyzed for each alternative, based upon potential locations.

As noted, wind resource dispatch is determined outside of the Market Simulator model and then entered as a fixed input. The National Renewable Energy Laboratory provided hourly shapes based on historical data. For additional detail on wind modeling and assumptions see Appendix B.1.

### Congestion and Congestion Costs

Transmission congestion affects the cost of serving loads and the ability to reach markets. In many locations, congestion grows with increases in loads unless new resources and transmission are added. The cost of congestion is defined as the increase in production (fuel) costs due to transmission constraints and losses.

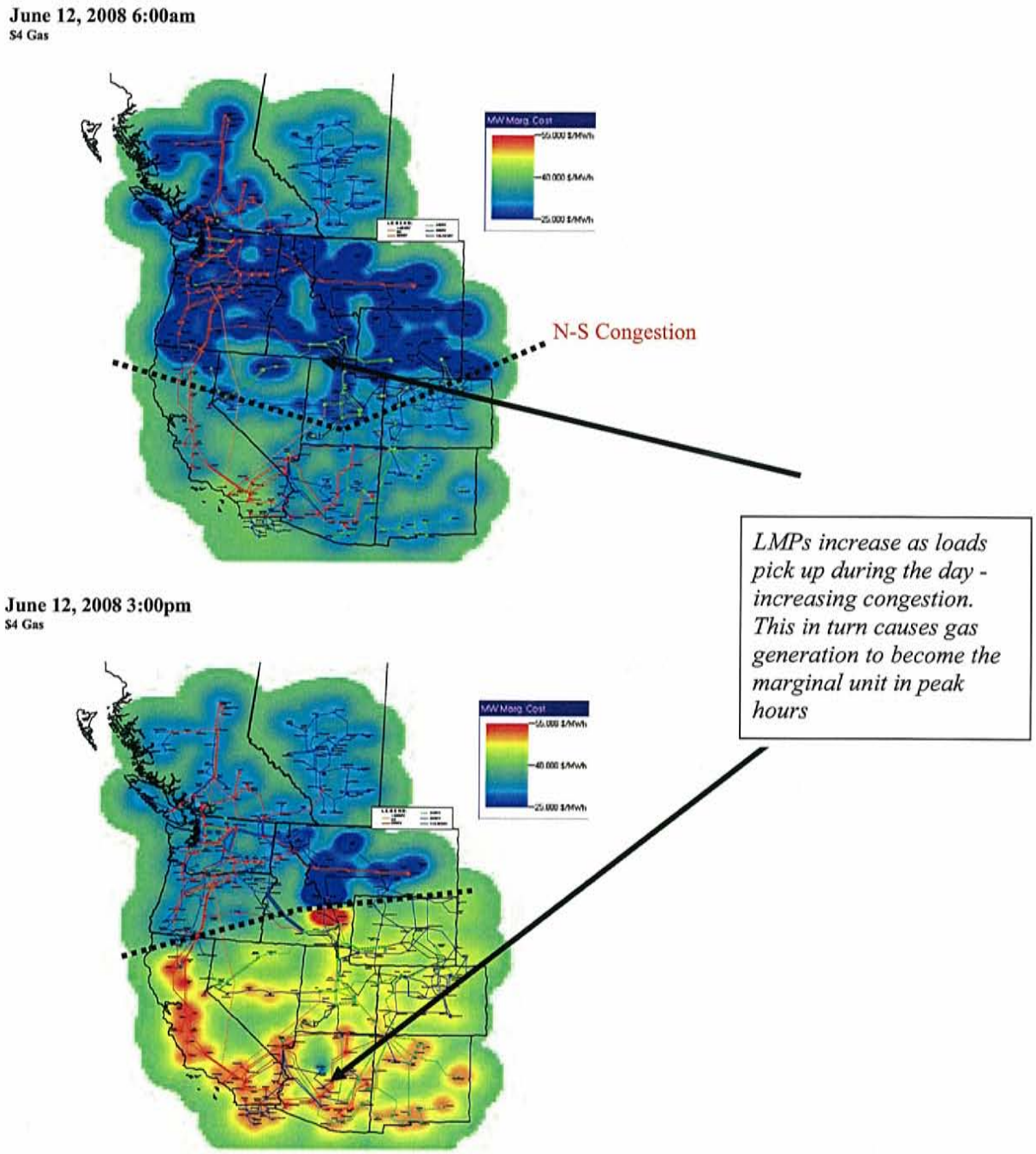
Congestion arises because power flows cannot be allowed to exceed the thermal, voltage or stability limits of transmission lines. Contract provisions and scheduling practices may also create constraints that lead to congestion. When there is congestion, transactions on the transmission system must be rerouted or curtailed to avoid exceeding the limits. This rerouting or curtailing generally adds to production costs because higher cost resources may need to be dispatched to reach loads. For example, if low-cost coal and wind generation cannot reach the load, natural gas-fired generation with higher operating costs may need to ramp up to match the consumption levels.

The marginal price is the least-cost way to deliver incremental power to load while respecting all transmission constraints. In the Market Simulator model, locational marginal prices (LMPs) represent the lowest cost of delivering the next MW of power to a particular location (node or bus), or the savings from reducing load by a MW at that location (i.e., the shadow price).
Differences in LMPs at any given time are caused by transmission congestion and losses. In the Market Simulator model, LMPs equalize across the interconnected system if no congestion exists, as is often the case. However, as loads grow at certain times of the day in the summer and winter seasons, LMPs diverge as congestion ensues. Transmission congestion affects the cost of serving loads because lower cost generation, prevented from reaching loads, is replaced by higher cost generation.

Congestion costs can be relieved by adding new transmission capacity; by removing institutional impediments, such as rate pancaking, to allow a fuller, more optimal use of the transmission system; by adding lower-cost resources in locations that avoid congestion; or through DSM and distributed generation behind the meter. Differences in LMPs provide a useful screening tool for targeting new investment. Increases in transmission capacity can be tested for the impact on LMPs and on system production costs.

The contour maps displayed in Figure 2-6 illustrate how locational marginal prices can change during two hours of a typical summer day. Blue indicates low marginal prices; red high marginal prices. The differences in colors indicate congestion is present.

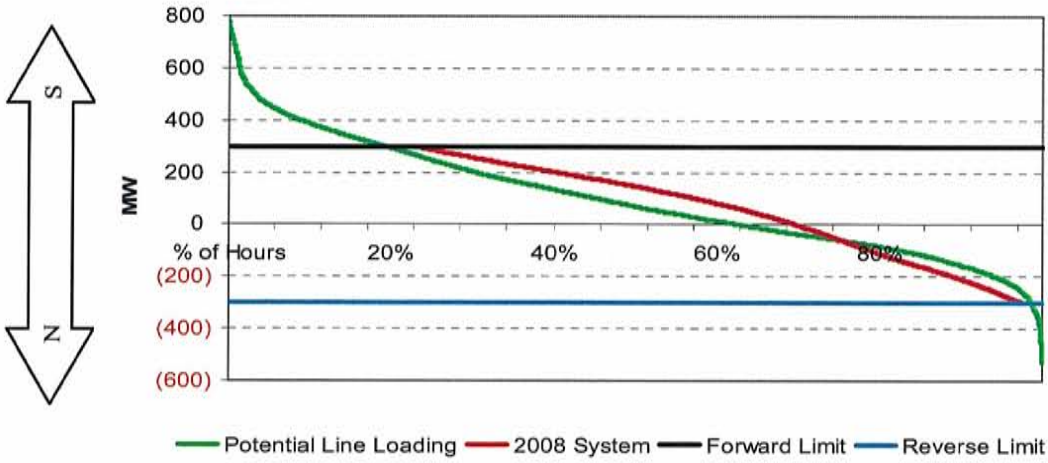
*Figure 2- 6: Example of How Congestion Arises as Loads Go Up during a Typical Summer Day*




The duration of congestion on transmission paths is also used when screening for bottlenecks and cost-effective investment. Figure 2-8 is an example of a duration curve. The green line shows the forecasted flow of power if there were no transmission constraints. The red line shows the forecasted flow with the 300 MW constraints enforced. The black line shows the transfer limit on

flows from north to south on the path. The blue line shows transfer limits south to north. Duration curves help target new investment in transmission. The need for new investment is informed by the percentage of the time an interface is congested. In the sample duration curve shown in Figure 2-7, the interface is congested 26% of the hours

*Figure 2- 7: Sample Duration Curve*




## D. Resource and Transmission Expansion Alternatives

The Work Groups created four resource addition scenarios for 2013. The scenarios reflect a range of resource development outcomes, from utility integrated resource plans (IRPs) to scenarios that capitalize on the region's abundant, no - or low - cost fuels (e.g., wind and Powder River Basin coal) for purposes of export to West Coast and Southwest markets. The Work Groups then developed transmission solutions to support these generation resource scenarios. Through an iterative process, the economic evaluation of these scenarios, referred to as Alternatives 1 through 4, set the stage for two sets of transmission expansion recommendations (Recommendations 1 and 2).

Alternative 1 reflects the IRPs of load serving entities (LSEs) in the RMATS region, where available. Alternative 2 is a "quasi" regional IRP that targets development of Powder River Basin (PRB) coal and wind resources. Alternatives 1 and 2 include generation additions in the RMATS region of 3,900 MW to meet the forecast load growth in the region, but the generation assumed in Alternative 2 would be too dependent on transmission expansions to be viable.

Alternative 3 includes the resources in Alternative 2, and adds 3,900 MW of PRB coal and wind resources for export to West Coast and Southwest markets. Alternative 4 includes the resources in Alternative 3, and adds another 3,900 MW increment of PRB coal and wind resources to double the export supply. Alternatives 3 and 4 are "export" scenarios which add resources in the RMATS region to supply west-wide markets and include 7,800 MW and 11,700 MW of new generation in the Rocky Mountain region, respectively.

Figure 2-3 shows the type and location of generation in the four scenarios.

*Table 2- 3: 2013 Resource Alternatives*

| State | Bubble | Gen Type | Name Plate Generation Values | | | |
|---|---|---|---|---|---|---|
| 2013 ALTERNATIVE CASES | | | 1 | 2 | 3 | 4 |
| Colorado | Colorado East | Coal | 1250 | 500 | 1540 | 2500 |
| | | Gas | 210 | 210 | 210 | 603 |
| | | Wind | 800 | 500 | 800 | 1500 |
| | Colorado West | Coal | | | | |
| | | Gas | | | | |
| | | Wind | | | 250 | 250 |
| Idaho | KGB | Coal | | | | |
| | | Gas | | | | |
| | | Wind | 125 | 125 | 125 | 125 |
| | Mid Point/Boise/Snake | Coal | 575 | | | |
| | | Gas | | | | |
| | | Wind | | | | 440 |
| Montana | Montana West | Coal | | | | |
| | | Gas | | | 260 | 260 |
| | | Wind | 225 | 280 | 500 | 1000 |
| | Broadview | Coal | | 250 | 500 | 750 |
| | | Gas | | | | |
| | | Wind | 0 | | 950 | 1000 |
| | Colstrip/Crossover | Coal | | 359 | 609 | 1109 |
| | | Gas | | | | |
| | | Wind | | 50 | 100 | 200 |
| Utah | Bonanza | Coal | | | | |
| | | Gas | | | | |
| | | Wind | | | | |
| | IPP | Coal | 200 | | 950 | 950 |
| | | Gas | | | | |
| | | Wind | | | | |
| | Utah North | Coal | | | | |
| | | Gas | | | | |
| | | Wind | 250 | 100 | 200 | 320 |
| | Utah South | Coal | 575 | 575 | 575 | 575 |
| | | Gas | 525 | 140 | 140 | 140 |
| | | Wind | | | 120 | 250 |
| Wyoming | Big Horn Basin | Coal | | | | |
| | | Gas | | | | |
| | | Wind | 250 | 250 | 250 | 250 |
| | Black Hills | Coal | | | | |
| | | Gas | | | | |
| | | Wind | | | | 125 |
| | LRS | Coal | | | | |
| | | Gas | | | | |
| | | Wind | | 500 | 500 | 1500 |
| | SW Wyoming | Coal | | | | |
| | | Gas | | | | |
| | | Wind | 925 | 1150 | 1000 | 2450 |
| | Wyoming | Coal | | 700 | 1400 | 2100 |
| | | Gas | 50 | | 50 | 50 |
| | | Wind | | | | 800 |
| WYO(IDA) | Jim Bridger | Coal | | 575 | 575 | 575 |
| | | Gas | | | | |
| | | Wind | | | 160 | 230 |
| WYO(MT) | Yellowtail | Coal | | | | |
| | | Gas | | | | |
| | | Wind | | | | |
| | Total Coal | | 2600 | 2959 | 6149 | 8559 |
| | Total Gas | | 785 | 350 | 660 | 1053 |
| | Total Wind Nameplate | | 2575 | 2955 | 4955 | 10440 |
| | Total Firm Energy | | 3900 | 3900 | 7800 | 11700 |

## E. Generation Alternatives for 2013

### Alternative 1: Existing IRPs

Alternative 1, which reflects the generation proposed by the LSEs in the RMATS region that have published integrated resource plans, tends to emphasize the development of new gas-fired generation close to load centers and thus represent a scenario with minimal new transmission additions. Some wind generation capacity was added to the IRPs resources so that total resource additions met the RMATS projection for load growth from 2008 to 2013.

Minimal transmission additions were identified in existing IRPs. Indeed, the plans probably do not identify all of the transmission additions that would be needed to accommodate the new generation, in particular, new wind generation. In the modeling of all alternatives, a phase shifter was included on the existing path between Montana and Idaho, two 100MVA transformers, at Flaming Gorge, were replaced by two 200MVA transformers and a new 230 kV line was added between Midpoint and Boise. Alternative 1 assumes no transmission to relieve constraints outside the RMATS region.

### Alternative 2: "Quasi" IRP for the RMATS Region

In Alternative 2, priority is given to developing PRB coal and wind resources. It adds 359 MW more coal generation and 380 MW more wind generation than Alternative 1. New gas-fired generation decreases from 785 MW to 350 MW. In Alternative 2, the coal and wind resource additions are located differently and are more transmission-dependent. The assumptions driving these relocations are: (1) the transmission cost for new Powder River Basin mine-mouth generation is less than coal transportation costs for coal generation sited elsewhere, and (2) wind conditions are of higher quality in southern Wyoming. Alternative 2 is the basis for Recommendation 1, which is described in Chapter 3.

Figure 2-8 is a sample chart that shows the most congested transmission paths in the Rocky Mountain region if the resources in Alternative 2 are added – but with no new transmission infrastructure. (Similar charts for Alternatives 1, 3, and 4 may be found in Appendix B.4) The figures within the blue circles are the percentages of time in a year during which transmission constraints would prevent the most economic power dispatch. The dollar number next to the transmission constraint represents how much interconnection-wide costs would decline by adding one additional MW to the transfer capacity of the path. This value will decline as each additional MW of transfer capacity is added.

*Figure 2- 8: Congestion If No Transmission Is Added in Alternative 2*

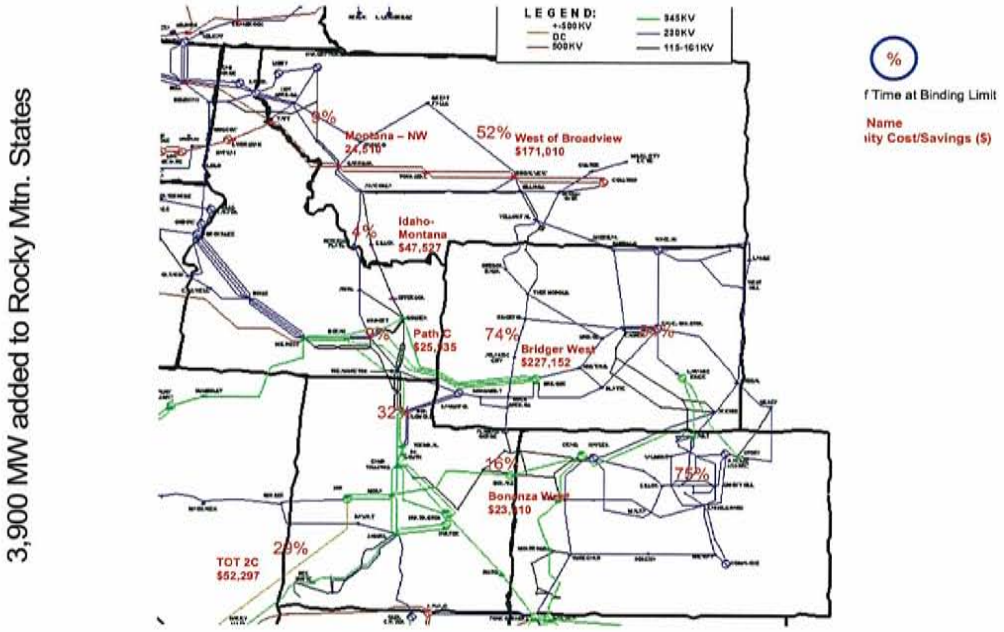
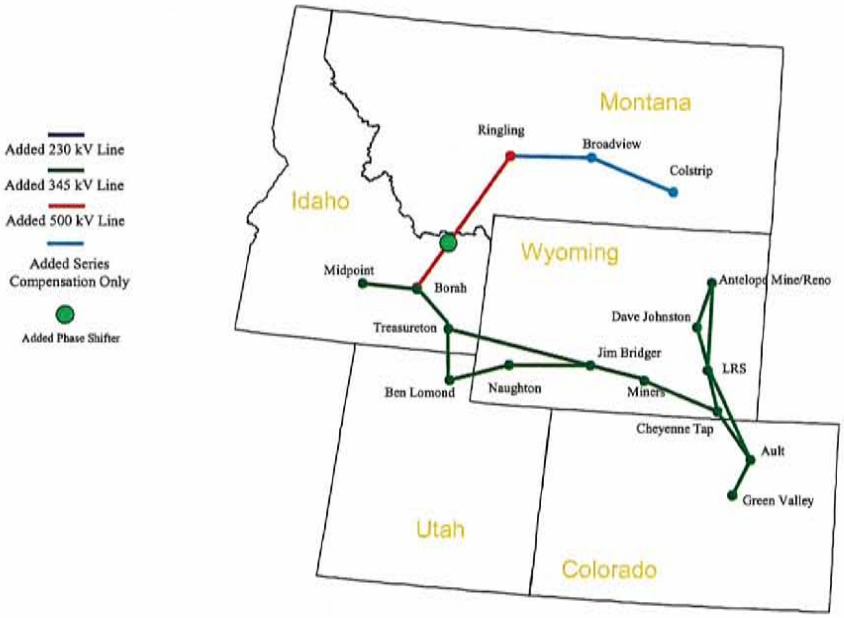



Figure 2-9 shows transmission additions to relieve the congestion in Alternative 2, including new 345 kV lines from Wyoming to the Colorado Front Range, from Idaho to Utah, and from Wyoming to Idaho. A 500 kV line is also added from Montana to Idaho which would include a phase shifter. The minimal transmission build included in Alternative 1 is also included in Alternative 2.

*Figure 2- 9: Transmission Additions in Alternative 2*

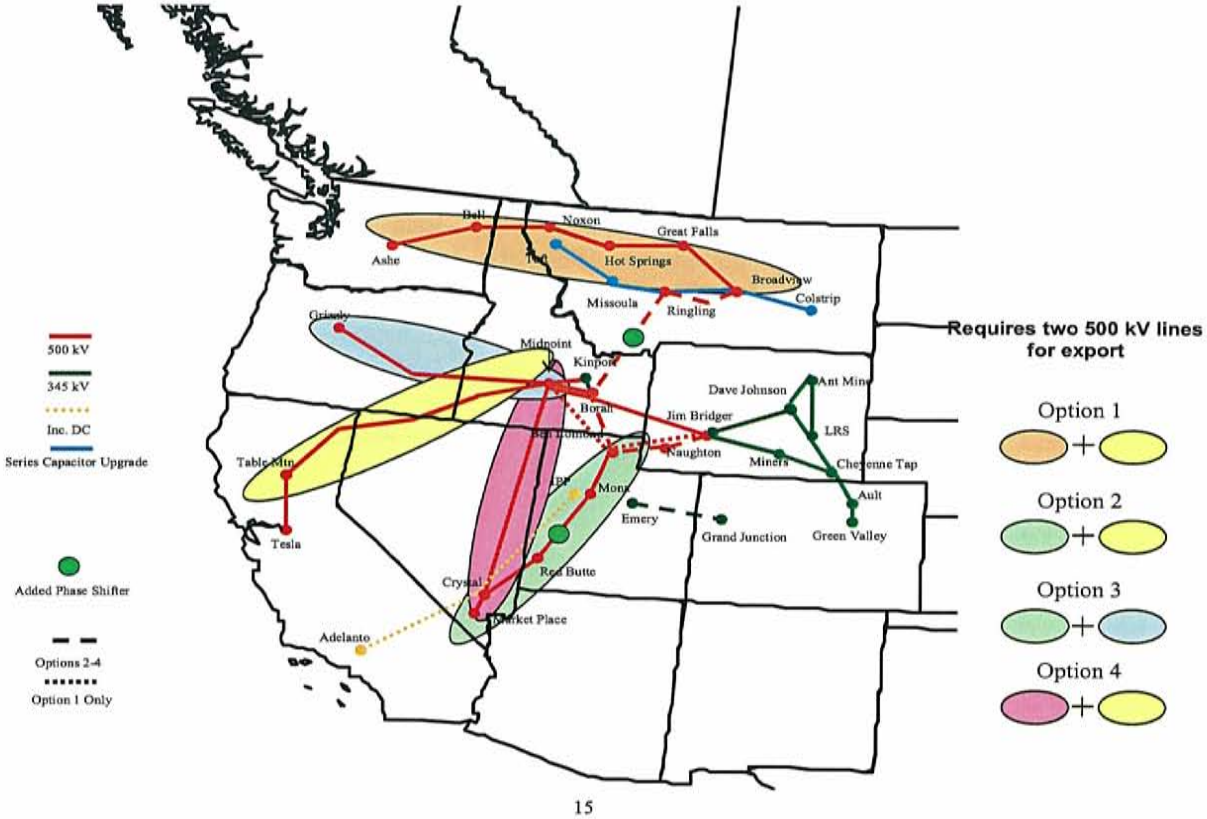


### Alternative 3: Double the Resource Additions in Alternative 2 for Export

Alternative 3 includes the resources and transmission additions in Alternative 2, and adds 3,900 MW of Powder River Basin coal and wind resources for export purposes outside the RMATS region. Alternative 3 contains a number of options to relieve transmission congestion. The Work Groups determined that at least two 500 kV transmission paths would be required from the Rocky Mountain region to the West Coast, and that these paths should not be in the same corridor. Figure 2-10 shows the four optional combinations of 500 kV lines that were studied (additional combinations are possible). The analysis revealed that total variable and fixed costs for each of the four paths were quite comparable, and that no one combination was clearly superior. Options for export paths should be subjected to a thorough review in RMATS Phase II. Alternative 3 is the basis for Recommendation 2, and is discussed in Chapter 3.

*Figure 2-10*

*Transmission Additions in Alternative 3*




The major differences in transmission expansions between Alternative 2 and Alternative 3 in the Rocky Mountain region are: (1) elimination of a second 345 kV line from Wyoming to the Colorado Front Range; (2) the addition of a 345 kV line from Colorado to Utah; (3) the upgrade of transmission from Wyoming to Idaho and from Wyoming to Utah from 345 kV to 500 kV; (4) the addition of a 500 kV line between Idaho and Utah; (5) and additional series compensation on the

existing 500 kV line within Montana. New 500 kV lines to move power from Montana to Washington and from Utah to southern Nevada were investigated. Three optional 500 kV lines were identified to move power from Idaho to southern Nevada, northern California, and central Oregon. The option combinations that were analyzed are:

1. New transmission from Montana to Washington and from Idaho to northern California.
2. New transmission from Utah to southern Nevada and from Idaho to northern California.
3. New transmission from Utah to southern Nevada and from Idaho to central Oregon.
4. New transmission from Idaho to southern Nevada and from Idaho to California.

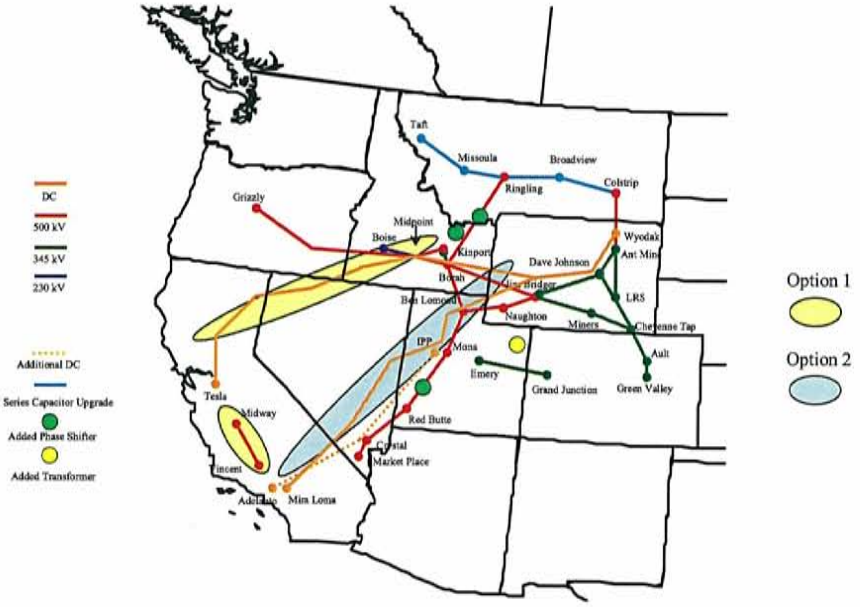
Common to all the options in Alternative 3 is the addition of new converter equipment to the existing 500 kV DC line from Utah to Southern California (the IPP line) to increase its capacity by 500 MW. The Work Groups did not analyze an option with two new 500 kV lines terminating in the Northwest because the delivery of that much power to the Northwest would probably require expensive upgrades to the Pacific Intertie to move the power to California.

**Alternative 4: Triple the Resource Additions in Alternative 2 for Export to West Coast**

Alternative 4 builds upon the resource and transmission additions in Alternative 3, adding another 3,900 MW of PRB coal and wind generating capacity for export purposes. This generation is sufficient to meet load growth in the Rocky Mountain region, and to export power equal to two times the region's load growth. Generation capacity additions in Alternative 4 total 11,700 MW.

Not surprisingly, without new transmission, Alternative 4 creates significantly more congestion than Alternative 3. To accommodate this level of new resources in the RMATS region, the Work Groups investigated two 500 kV DC lines from Wyoming to northern or southern California.

*Figure 2- 101: Transmission Additions in Alternative 4*



## F. Conclusions

From these alternatives, the Steering Committee proposed two recommendations for further study in RMATS Phase II:

- Recommendation 1, which is predicated on the resource and transmission build in Alternative 2.
- Recommendation 2, an export case that reflects Alternative 3.

These recommendations and economic analyses are described in Chapter 3.

# Chapter 3 - Recommendations for Transmission Expansion

## A. Introduction

As noted in Chapter 2, the Work Groups developed and evaluated generation and transmission alternatives through a series of scenarios and simulation studies. From these economic screening analyses and with the professional judgment of Work Group members, two recommendations are made to expand the region's transmission system. These recommendations are dependent upon further technical studies to address siting, financing, cost allocation and recovery, and other issues in RMATS Phase II. They are endorsed by the Steering Committee, and are respectfully offered to the sponsoring Governors, State and Federal regulators and potential project participants for their consideration.

The two transmission expansion recommendations, along with two reference cases, are described in this chapter. Production cost results from system simulation studies are presented, as are cost/benefit analyses that take into account production costs, capital investment requirements, and annualized fixed costs. Economic benefits and losses are then estimated by region within the West. Chapters 4 and 5 address the challenging issues that lay ahead for further work on these recommendations in Phase II and beyond.

## B. Recommendations for Transmission Expansion

The RMATS Steering Committee urges that the following transmission recommendations be pursued in Phase II:

- Recommendation 1, consisting of three transmission expansion projects within the Rocky Mountain region. These include a Montana System Upgrade, a Bridger Expansion, and a Wyoming to Colorado Project.
- Recommendation 2, consisting of a larger transmission build, extending outside the Rocky Mountain region to enable exports from the Rocky Mountain region.

The RMATS Steering Committee also supports two projects that are currently being analyzed by local entities. These incremental projects are relatively low-cost enhancements that provide economic benefits and can be accomplished in the near term to resolve some immediate congestion problems. The projects involve adding a phase shifter on the Idaho to Montana Amps line and upgrading the capacity of two transformers on the Flaming Gorge line. The economic analysis of these investment priorities is included in Appendix B.3.

### Recommendation 1: Projects within the Rocky Mountain Footprint

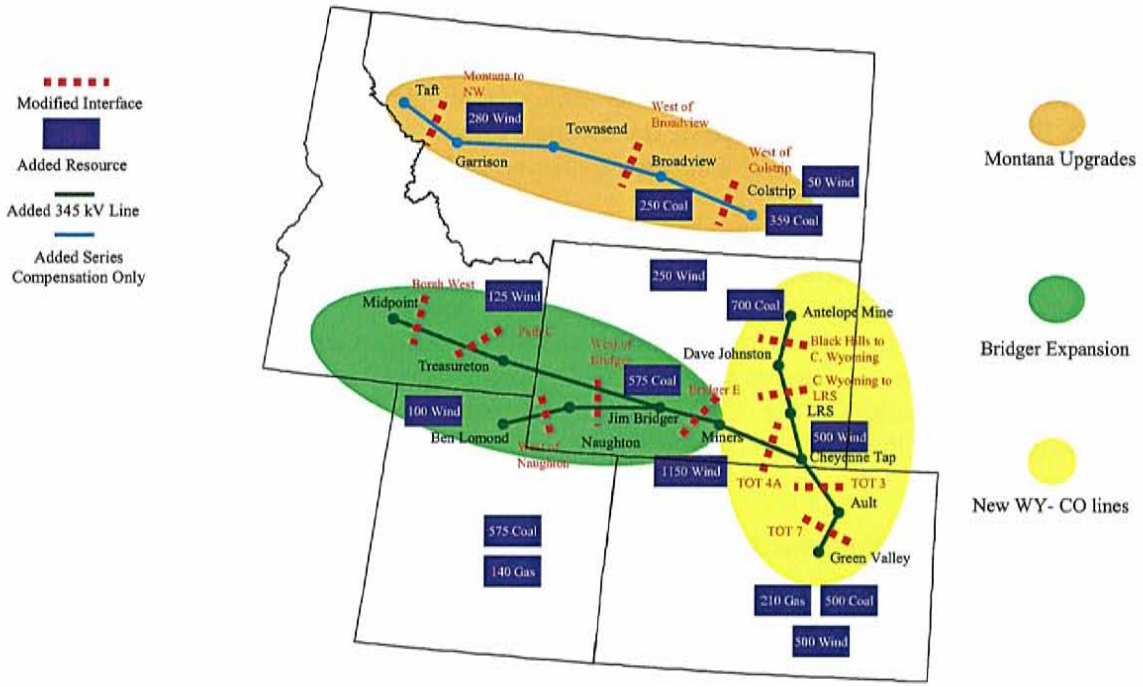
Figure 3-1 shows the three discrete projects included in Recommendation 1. These expansions include:

- Montana Upgrades (tan oval),
- Bridger Expansion (green oval), and

- Wyoming to Colorado Project (yellow oval).

This recommendation is predicated on the new wind capacity and coal-fired generation additions as shown in Figure 3-1. The new capacity will meet expected load growth in the Rocky Mountain region.

*Figure 3- 1: Recommendation 1: Transmission Expansion in the Rocky Mountain Area*




The capital cost for Recommendation I is estimated to be $970 million for the three transmission expansion projects and $6.604 billion for generating resources. Using reasonable assumptions, an economic comparison of Recommendation 1 with the two reference cases indicates these three projects are economic, producing annual net savings of between $61 million and $531 million. While each project is discrete, the three projects together provide the greatest benefit to the region.

**Montana System Upgrade Project**

This project upgrades the existing Montana 500 kV transmission system to enable exports from the Rocky Mountain region to the Pacific Northwest. This project does not include new transmission lines. By installing series compensation in the 500 kV lines from Colstrip to Taft, adding a 500/230 kV autotransformer at Colstrip, and adding two new substations on the 500 kV transmission system near Ringling and Missoula, transfer capacity on this path will increase by 500 MW. The capital costs for the Montana System Upgrade project are estimated to be $72 million.

These transmission additions efficiently reduced the congestion created by the assumed generating resource additions, which include 330 MW of nameplate capacity wind generation and 609 MW of coal-fired generation in Montana. Several transmission options were considered to expand capacity to move this additional generation, including transmission from Ringling, Montana, to Borah, Idaho,

transmission from Colstrip to Northern Wyoming, and upgrades to the existing Montana 500 kV system. The Ringling-Borah transmission option relieved the congestion but provided more capacity than would be needed for the assumed generation additions. A transmission line into Northern Wyoming did not relieve the congestion across cut planes in Montana.

The Montana System Upgrade is expected to have limited siting requirements. All the impacts are local in nature and a new transmission corridor is not required. The additions at the Colstrip and Broadview buses constitute upgrades to existing substation sites and will have little if any environmental impact. The new substation sites will have minimal siting requirements. This project may be completed within a two-year period. Table 3-1 shows the transfer capacity associated with the Montana System Upgrade.

*Table 3- 1: Recommendation 1: Transmission Expansion in the Rocky Mountain Area*

| Interface | Transmission Addition | Before (Reverse) – Forward | After (Reverse) – Forward | Incremental (Reverse) – Forward |
|---|---|---|---|---|
| West of Colstrip | Added Series Capacitor | N/A - 2,598 | N/A – 3,098 | +500 |
| West of Broadview | Added Series Capacitor | N/A – 2,572 | N/A – 3,072 | +500 |
| Montana to Northwest | Added Series Capacitor | (1,350) - 2,200 | (1,350) - 2,700 | +500 |

**Bridger Expansion Project**

Expansion of the Bridger 345 kV transmission system involves the addition of 345 kV transmission facilities from Miners to Bridger in Wyoming and from Bridger to Ben Lomond in Utah and to Midpoint in Idaho. These additions would increase transfer capacity by an estimated 1,350 MW and support the resource additions of 1,375 MW of wind generation and 575 MW of (Bridger) coal-fired generation in southwest Wyoming and southern Idaho. The capital cost of the Bridger Expansion project is estimated to be $580 million.

A new transmission corridor may be required between Naughton and northern Utah, and a new transmission corridor will be required between Bridger and Midpoint (potentially traversing an environmentally sensitive area north of Bear Lake in southern Idaho). New substation sites could have siting requirements. Siting issues may be reduced through use of existing lower voltage transmission corridors. This project may be completed within a five-year period. Table 3-2 shows the increases in transfer capacity with the recommended Bridger Expansion.

*Table 3- 2: Bridger Expansion Interface (Path) Capacity Additions*

| Interface | Addition | Before (Reverse) – Forward | After (Reverse) – Forward | Incremental (Reverse) – Forward |
|---|---|---|---|---|
| Bridger West- w/ series comp | Bridger to Treasureton 345kV<br>Bridger to Naughton 345kV | N/A – 2,200 | N/A – 3,550 | +1,350 |
| Borah West - w/ series comp<br><br>Path C- w/ series | Treasureton to Midpoint 345kV<br>Loop in Ben Lomond to Borah at Treasureton | N/A – 2,307<br><br>(750) – 750 With seasonal variation | N/A – 3,057<br><br>(1,500) – 1,500 | +750<br><br>+750 (Nominal) |
| West of Naughton- w/ series comp | Naughton to Ben Lomond 345kV | N/A – 920 | N/A – 1,520 | +600 |
| Bridger East | Miners to Jim Bridger 345kV | (600) - 600 | (1,100) – 1,100 | +500 |

**Wyoming to Colorado Transmission Project**

This project involves the addition of a 345 kV line from northeastern Wyoming across the constrained path between Wyoming and Colorado to Denver. The new line is estimated to increase capacity by 500 MW. The addition of series compensation to this new line (and potentially other lines) is estimated to increase capacity by an additional 250 MW and support the assumed resource additions of 500 MW of wind (nameplate capacity) and 700 MW of coal-fired generation capacity. The capital requirements for the Wyoming to Colorado project are an estimated $318 million.

The new 345 kV line would have substation interconnections in Wyoming, potentially in the Dave Johnston, Laramie River Station and Cheyenne areas. It would also require an interconnection in northern Colorado, perhaps at the Ault substation, with a final destination near the Green Valley substation northeast of Denver. Congestion resulting from the assumed generation additions would be reduced from an estimated high of 73 percent to below 30 percent with these line additions. Siting issues may be reduced through use of existing lower voltage transmission corridors. This project may be completed within a five-year period. Table 3-3 shows the increased transfer capacity associated with the Wyoming to Colorado Project.

*Table 3- 3: Wyoming to Colorado Interface (Path) Capacity Additions*

| Interface | Addition | Before (Reverse) – Forward | After (Reverse) – Forward | Incremental (Reverse) – Forward |
|---|---|---|---|---|
| Black Hills to C. Wyoming | Antelope Mine to DJ 345kV | (332) - 332 | (832) - 832 | +500 |
| LRS to C Wyoming | DJ to LRS 345kV | (640) - 640 | (1,140) – 1,140 | +500 |
| TOT 3- w/ series comp | Cheyenne Tap to Ault 345kV | N/A – 1,424 | N/A – 2,174 | +750 |
| TOT 7- w/ series comp | Ault to Green Valley 345kV | N/A – 890 | N/A – 1,640 | +750 |
| TOT 4A | Miners to Cheyenne Tap 345kV | N/A – 810 | N/A – 1,560 | +750 |

**Recommendation 2: Export Projects Beyond the RMATS Footprint**

RMATS also recommends transmission expansions that extend beyond the Rocky Mountain states to enable exports of generation. This is a longer-term export proposal that: (1) includes the generating resources assumed for the projects in Recommendation 1; (2) assumes construction of an additional 3,900 MW of coal generation and remote wind resources; and, (3) builds two export paths to the West Coast, Nevada and Arizona markets. The viability of Recommendation 2 depends on the fuel preferences of load-serving entities (LSEs) outside the Rocky Mountain region.

Recommendation 2 includes two of five optional 500 kV paths shown in the colored ovals in Figure 3-2. Additional transmission upgrades in the Rocky Mountain region beyond those identified in Recommendation 1 are also part of Recommendation 2, including:

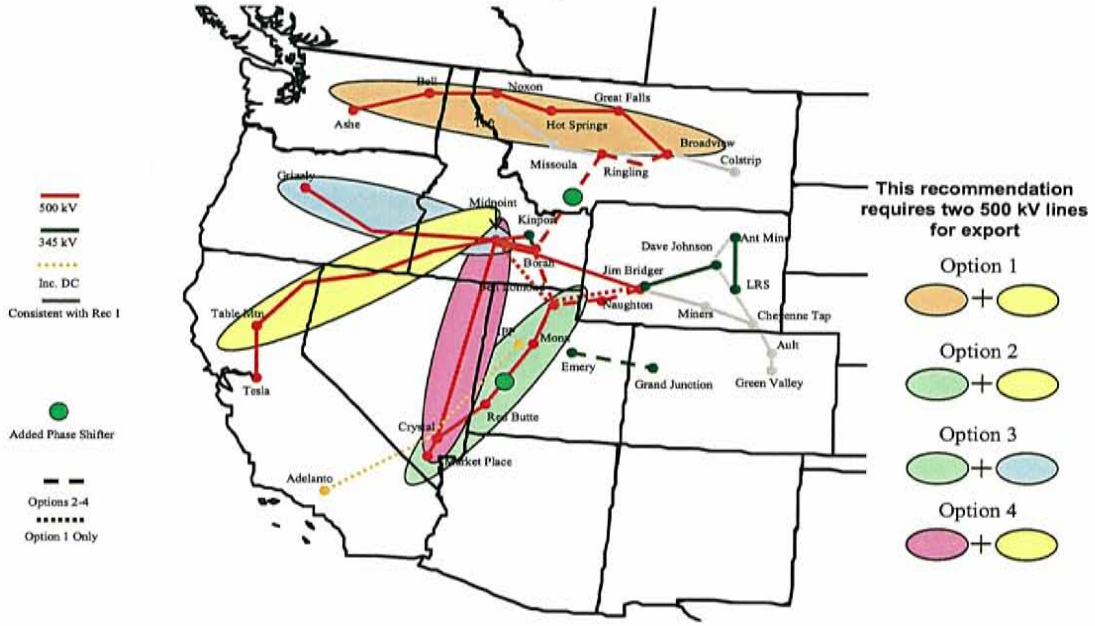
- Upgrading the Bridger Expansion project from 345 kV to 500 kV west of Bridger. Specifically, new 500 kV lines would be added between Bridger and Ben Lomond, Ben Lomond and Mid Point, Ben Lomond and Kinport; Borah and Midpoint, Borah and Ringling (including a phase shifter), and Ringling and Broadview.

- Adding new 345 kV lines between Grand Junction and Emery, Antelope and Laramie River Station, and Dave Johnston to Bridger.

The capital cost for the Recommendation 2 transmission expansion is estimated to be $4.265 billion and $ 10.05 billion for generating resources.

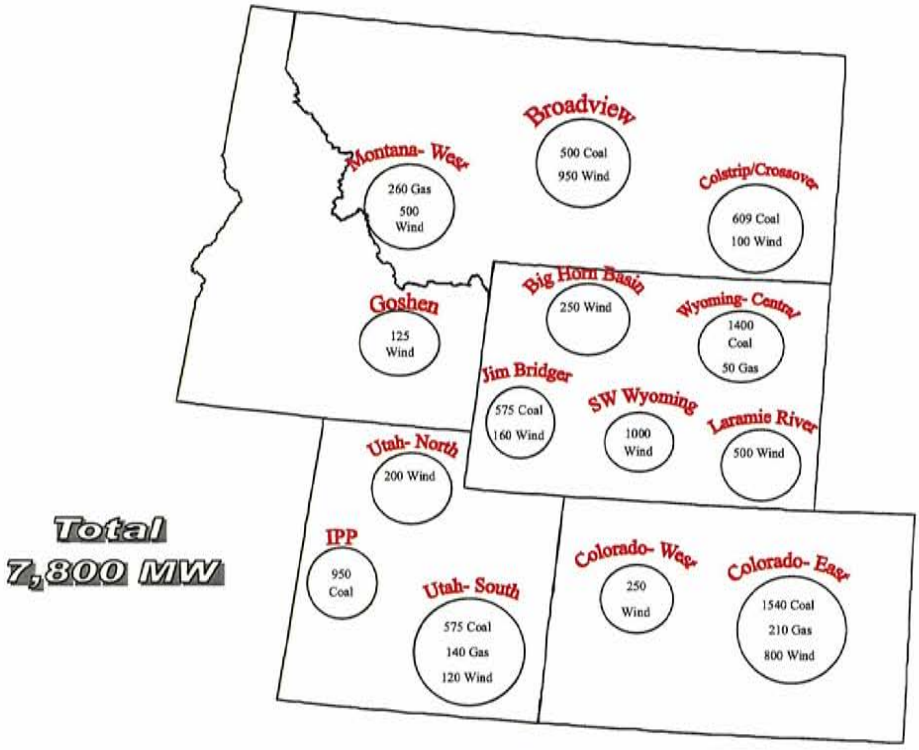
*Figure 3- 2: Transmission Expansion Extending Beyond the Rocky Mountain Region*

*Recommended for Further Development*



The economic analysis for these export options is based on the generation additions shown in Figure 3-3.

*Figure 3- 3: Generation Additions Assumed in Recommendation 2*




Total resource additions are assumed to include 660 MW of new gas-fired generation, 4,955 MW of remote wind resources (nameplate capacity) and 6,149 MW of coal-fired Powder River Basin generation.

To export this remote generation, the existing IPP-Adelanto DC line would be upgraded and two 500 kV lines to export markets would be needed. Five potential paths were examined for these 500 kV lines. Study results show the economic benefits for different combinations of paths to be similar. Decisions on which two paths to pursue will need to be determined as technical studies, right-of-way issues, cost recovery issues, and financing options are addressed in Phase II.

Table 3-4 summarizes the estimated increases in transfer capacity from the transmission facilities added in Recommendation 2.

*Table 3- 4: Capacity Increases from Construction of Export Transmission*

| Interface | Option | Addition | Before (Reverse) – Forward | Incremental (Reverse) – Forward |
|---|---|---|---|---|
| West of Colstrip | 1-4 | Added Series Capacitor | N/A - 2,598 | +500 |
| West of Broadview | 1-4<br>2-4<br>1 | Added Series Capacitor<br>Broadview to Ringling 500kV<br>Broadview to Hot Springs (via Great Falls) 500kV | N/A – 2,572 | +500<br>+1000<br>+1000 |
| Montana to Northwest | 1-4<br>1 | Added Series Capacitor<br>Hot Springs to Noxon 500kV | (1,350) - 2,200 | +500<br>+1000 |
| West of Hatawai | 1 | Noxon to Ashe (via Bell) 500kV | N/A – 4000 | +1000 |
| Idaho to Montana | 2-4 | Ringling to Borah 500 kV [phase shifter] | (337) – 337 | +1000 |
| Bridger West | 1-4<br>1<br>2-4 | Bridger to Borah 500kV (series comp)<br>Bridger to Ben Lomond 500kV (series comp)<br>Bridger to Naughton 500kV (series comp) | N/A – 2,200 | +1000<br>+1000<br>+1000 |
| Borah West | 1-4<br>1-4 | Kinport to Midpoint 500kV (convert 345kV)<br>2 Borah to Midpoint 500kV | N/A – 2,307 | +500<br>+2000 |
| West of Naughton | 2-4<br>1 | Naughton to Ben Lomond 500kV (series comp)<br>Bridger to Ben Lomond 500 kV | N/A – 920 | +1000<br>+1000 |
| Path C | 2-4<br>1 | Ben Lomond to Borah 500kV<br>Ben Lomond to Midpoint 500 kV | (750) -750<br>w/ seasonal variations | +1000<br>+1000 |
| Bridger East | 1-4 | Miners to Jim Bridger 345kV | (600) – 600 | +500 |
| Black Hills to C. Wyoming | 1-4 | Ant Mine to DJ 345kV | (332) – 332 | +500 |
| Black Hills to LRS | 1-4 | Ant Mine to LRS 345kV | (332) – 332 | +500 |
| LRS to C Wyoming | 1-4 | DJ to LRS 345kV | (640) – 640 | +500 |
| TOT 1A | 1-4 | Emery to Grand Junction 345kV | N/A – 650 | +500 |
| TOT 3 | 1-4 | Cheyenne Tap to Ault 345kV | N/A - 1,424 | +500 |
| TOT 7 | 1-4 | Ault to Green Valley 345kV | N/A – 890 | +500 |
| TOT 4A | 1-4 | Miners to Cheyenne Tap 345kV<br>Dave Johnston to Jim Bridger | N/A – 810 | +500<br>+500 |
| TOT 2C | 2-3 | Ben Lomond to Market Place (via Mona, Red Butte & Crystal) 500kV [phase shifter] (series comp) | (300) – 300 | +1200 |
| Idaho to Las Vegas | 4 | Midpoint to Market Place (via Crystal) 500kV (series comp) | N/A | +1200 |
| Idaho to N. California | 1, 2, 4 | Midpoint to Tesla (via Table Mtn) 500kv (series comp) | N/A | +1500 |
| Midpoint-Summer Lake | 2 & 3 | Midpoint to Grizzly (series comp) | (400) – 1,500 | +1000 |
| IPP DC | 1-4 | Add Converter Stations | (300) – 1,920 | +500 |
| Others | 1-4<br>1-4 | LRS to Cheyenne Tap 345kV<br>Borah to Kinport 345kV | N/A | N/A |

## C. Two Reference Cases

Recommendations 1 and 2 are predicated on the development of remote coal and wind resources to meet the region's load growth and to serve export markets, and they entail substantial new investment in transmission. Two reference cases were created to compare economic benefits of the remote generation/transmission intensive recommendations and alternatives that do not rely on new transmission. These reference cases avoid or minimize new transmission investment primarily by locating new generation near loads.

The reference cases differ in the type and location of resource additions in the Rocky Mountain region. The All-Gas Reference Case assumes that load growth is met through new gas-fired generation. The IRP-Based Reference Case includes new gas-fired generation, but also new coal generation, primarily at existing sites, and new wind resources. The reference cases are similar in that both add the same overall resource capacity, and both use the same gas and coal fuel prices and hydro condition assumptions. Both cases assume that generation additions outside the Rocky Mountain states after 2008 will take the form of gas-fired generation located near loads. Both cases also include no significant transmission investment other than for resource integration. As a result, the reference cases bracket a range of potential outcomes that would occur if little new transmission were built.

**All-Gas Reference Case:** This case assumes that load growth in the Rocky Mountain states for the 2008 to 2013 period will be met exclusively by adding gas-fired generation located close to load centers. Capital investment in this case is limited to gas-fired generation additions and associated interconnection costs.

The All-Gas Reference Case is representative of the recent past. In the 1990's, nearly all load growth in the West was met by building gas-fired plants. The All-Gas Reference Case assumes this trend will continue, and it is akin to a "do-nothing" case from a transmission expansion perspective. This case is useful for comparing the fuel and investment costs of alternative resources, and for measuring the value of diversifying fuels. Indeed, annual west-wide production costs in Recommendations 1 and 2 are $1.238 to $2.560 billion lower than the All-Gas Reference Case.

**IRP-Based Reference Case:** This case is based on resource additions in the integrated resource plans of LSE's in the Rocky Mountain states, where available. Where IRPs are not available, wind capacity is assumed to fill the gap. The IRP-Based Reference Case presumes significant wind and some coal resources are added. Because little transmission is added in the IRP-Based Reference Case, wind generation additions are limited by transmission capacity and the physical ability of coal plants to rapidly cycle to meet changes in the output of wind generators[1]. Consequently, production costs are substantially lower than in the All-Gas Reference Case because of lower fuel costs. Capital requirements are higher than in the All-Gas Reference case because of the higher up-front cost of remote coal and wind units.

The IRP-based case is a compilation of existing IRPs, and as such, represents the current planning path for major LSEs in the RMATS footprint; but they may, however, not include the transmission investment that would be required to integrate the wind and other resources they propose. The annual reduction in the West's production costs between the IRP-based and All-Gas Reference Cases ($972 million) indicates the value that may be created by capitalizing on the region's lower cost fuels. To the extent that transmission bottlenecks preclude the wind and coal generation in IRPs from being developed, this reduction in production costs would not materialize as LSEs turn to gas-fired plants to meet load growth.

The reduction in annual production costs between the IRP-based reference case and Recommendation 1 ($266 million) reflects the value that could be created by moving from company-specific resource planning to regionally integrated resource and transmission planning.

[1] There may be new coal generation technologies that could minimize the problem of cycling coal plants to accommodate more wind generation, such as Integrated Gasification/Combined Cycle (IGCC) coal plants coupled with temporary gas storage capability that would enable the gasification process to operate continuously, but the burning of the gas to generate electricity could better match periods of slack wind generation.

The two reference cases represent a range of costs for meeting load growth in the Rocky Mountain region if transmission expansions do not occur. The following is a comparison of costs and savings between Recommendations 1 and 2 and the two reference cases.

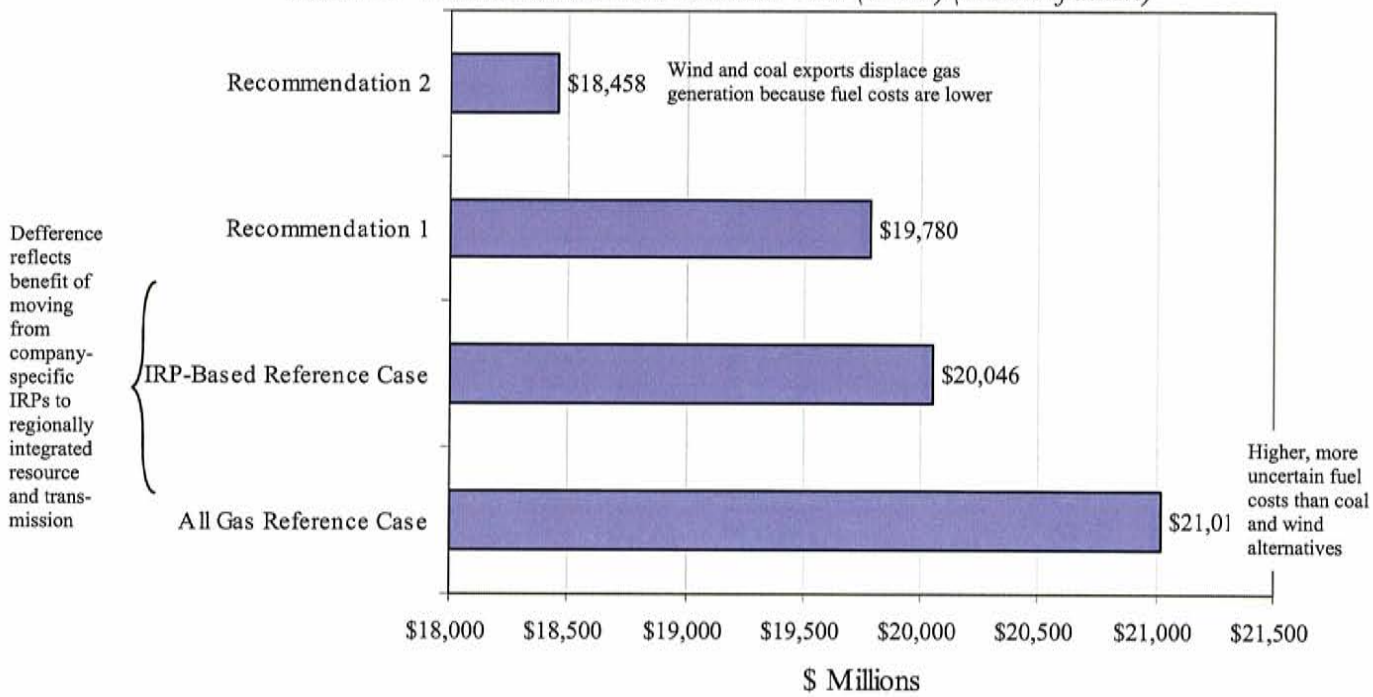
## D. Economic Evaluation

The economic evaluation begins with a simulation of productions costs for 2013. Sensitivities on certain key assumptions are included. Capital requirements and annualized fixed costs are then calculated and combined with the production costs for an overall economic comparison. The distribution of economic gains and losses associated with changes in production costs are also determined.

### Production Costs

The simulation logic seeks to minimize production costs for the Western Interconnection, including fuel and other variable operating and maintenance (O&M) costs. Production costs for Recommendations 1 and 2 and the two reference cases are illustrated in Figure 3-4. Production costs are lower in Recommendations 1 and 2 than in the two Reference Cases because the addition of transmission and large amounts of coal- and wind generation displace higher-cost natural gas-fired generation. The production costs produced in the All-Gas and IRP-Based Reference Cases are estimated to be $21.018 billion and $20.046 billion, respectively. Production costs for Recommendation 1 are estimated to be $19.780 billion, a reduction of $1.238 billion and $266 million, respectively, when compared to the All-Gas and IRP-Based Reference Cases. Production costs for Recommendation 2 are estimated to be $18.458 billion, a substantially greater reduction from the All-Gas and IRP-Based reference cases of $2.56 billion and $1.588 billion, respectively.

*Table 3- 5: Western Interconnection Production Costs (VOM) (millions of dollars)*



## E. Sensitivities

The production costs in Figure 3-4 are calculated with natural gas prices of $6.50 in 2013 dollars ($5.20 gas in 2004 dollars) and medium hydro conditions. See the Key Assumptions discussion in Chapter 2. Production costs associated with Recommendations 1 and 2 are sensitive to natural gas prices, and, to a lesser extent, hydro conditions. Simulations were performed using a reasonable range of potential natural gas prices and hydro conditions. Other sensitivity analyses were performed as well. Results from all the sensitivity analyses can be seen in Appendix B.7.

Under low natural gas prices, annual production costs are lower in all cases. Even in the low gas sensitivity, the fuel costs for coal-fired and wind resources are lower than the fuel costs for gas-fired resources. This causes already-constructed coal-fired and wind resources to continue to be dispatched before existing gas-fired resources. To further test this, a high gas price sensitivity of $8.50 was performed for the All Gas Reference Case. This sensitivity results in higher production costs ($3.5 billion increase over the $6.50 gas price case). This increase is essentially due to the higher gas price, not to a change in redispatch of resources.
Under low hydro conditions, production costs increase in all four cases. On a comparative basis, the savings from Recommendations 1 and 2 increase during a low water year. Production costs are shown to be much less sensitive to hydro conditions than to gas prices.

The comparative result of these sensitivities is summarized in Figure 3-5. Note that the production costs are lower under Recommendations 1 and 2 than the reference cases even with low gas prices.

*Figure 3- 4: Western Interconnection Production Costs*

*(Variable Operating and Maintenance Cost in millions of dollars)*

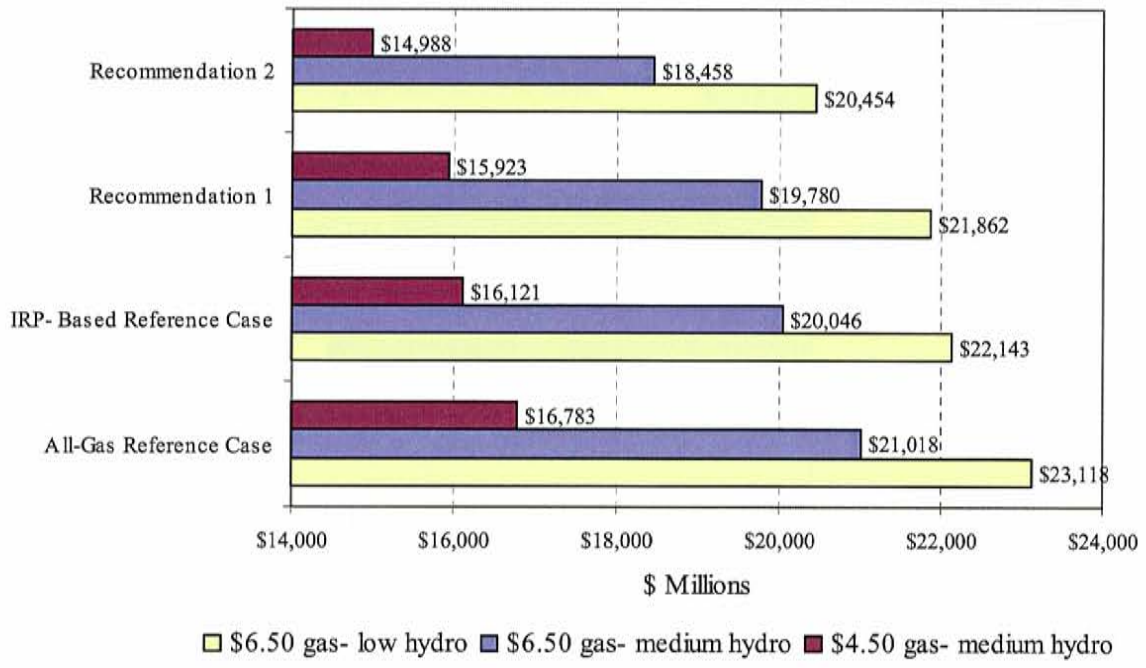


*Table 3- 6: Western Interconnection Production Cost Savings from Reference Cases*

| ($ - Millions) | | |
|---|---|---|
| | **Reference Case** | |
| | **All-Gas Case** | **IRP-Based Case** |
| **Recommendation 1** | | |
| Base Case *($6.50 gas-median hydro)* | (1,238) | (266) |
| Low Natural Gas Price *($4.50 gas-median hydro)* | (860) | (197) |
| Low Hydro Condition *($6.50 gas-low hydro)* | (1,257) | (281) |
| **Recommendation 2** | | |
| Base Case *($6.50 gas-median hydro)* | (2,560) | (1,588) |
| Low Natural Gas Price *($4.50 gas-median hydro)* | (1,795) | (1,132) |
| Low Hydro Condition *($6.50 gas-low hydro)* | (2,665) | (1,689) |

The robustness of Recommendations 1 and 2 was tested by assuming a significant increase in demand-side management (DSM) activities. To reflect more aggressive DSM programs, the energy loads within the Rocky Mountain region are assumed to grow by 1.05% less per year than in the reference cases and that energy loads outside the Rocky Mountain region would grow by 0.51% less per year than in the reference cases. Peak load reductions are assumed to be 1.5 times the energy reduction. Within a couple of years of phase-in and including the five-year period between 2008 and 2013, peak loads in the Rocky Mountain region in 2013 are assumed to be reduced by 12% and energy by 8% while in the coastal states the reduction would be half that due to their already existing, more aggressive DSM programs. See Appendix G for discussion of these assumptions. Using these DSM assumptions, load growth in the Rocky Mountain region between 2008 and 2013 would be only 100 MW, thus negating the need for significant transmission additions to serve load in the region. In this case, both Recommendations 1 and 2 can be viewed as export projects.

To reflect potential carbon dioxide constraints, a sensitivity analysis was conducted assuming $5/ton and $15/ton adders applied to $CO_2$ emissions from new resource additions. This level of adder does not impact the dispatch of plants that the model assumes are built, and this sensitivity showed that the dispatch of these new resources was unaffected by these levels of adders.[2]

[2] The impact of a $CO_2$ adder on the decision of which existing plants to dispatch is much less than the impact of the adder on the choice of generation plant to build. Just as the economics of choosing between driving a car and riding a bus become dramatically different if you already own a car: All the fixed costs of owning the car are no longer relevant and you you would compare the incremental cost of running the car to the cost of a bus ticket. Thus, the greatest opportunity to reduce carbon emissions occurs in the choice of which resources to build. The ABB Market Simulator focuses on the use of the transmission system and has limited abilities to analyze generation resource choices. The models that utilities use in IRP efforts are better at evaluating resource addition options, but these models typically have very limited capabilities to model the transmission system. A back-of-the-envelope analysis using various assumptions (e.g., $6/MMBTU gas, 35% capacity availability for wind, 85% availability for

## F. Capital Requirements

The west-wide reductions in annual production costs from Recommendations 1 and 2 appear large. This conclusion is valid across a reasonable range of natural gas prices and hydro conditions, but this potential benefit is only part of the story. Alternatives 1 and 2 contemplate substantially higher levels of capital investment to build the needed transmission and to build coal and wind generation resources that have higher up-front costs than gas-fired generation. The economic comparisons are completed by combining fuel and other variable O&M costs with annualized capital and fixed O&M costs. The total costs of Recommendations 1 and 2 are then compared to the total costs of the reference cases for a more complete economic picture.

Table 3-7 compares the total costs of Recommendation 1 and 2 and the two reference cases. Annualized costs associated with each scenario are shown in the column labeled "Representative Year." This column represents a snapshot of real levelized annual capital costs for each case. Fuel and other variable O&M
(production costs) are combined with annualized fixed costs to give a full cost picture of each scenario.
The annual production costs from Figure 3-6 are shown in lines 1 through 3.

Capital requirements for each case are shown in the column labeled "Initial Investment" and are grouped into generation resource investment and transmission investment. The generation resource investment numbers include wind, gas and coal capital investment as well as associated transmission integration investment (lines 5 to 11). In the case of Recommendation 2, generation investment outside the Rocky Mountain region is adjusted downward to the extent the Rocky Mountain region builds resources for export (line 12). Transmission costs include capital investment associated with transmission lines and any required customized equipment costs (lines 21 to 24).

Capital requirements for the All-Gas and IRP-Based Reference Cases are $2.257 and $6.012 billion, respectively; and all of this investment is in generation with no transmission capital assumed.[3] Generation capital for Recommendations 1 and 2 are $6.604 and $10.050 billion, respectively[4]. Transmission capital requirements assumed for Recommendations 1 and 2 are $970 million and $4.265 billion, respectively.

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coal and gas, and assumptions on capital costs and carrying charges) indicates that even with a $5/ton $CO_2$ adder, coal is the lowest cost option. However, at $10/ton $CO_2$ adder, wind becomes the lowest cost option.

[3] Limited transmission investments to integrate local generation are included in the generation capital assumptions.

[4] The capital requirements for Recommendation 2 include most of the capital requirements associated with Recommendation 1.

*Table 3- 7: Economic Comparisons*

| (2004 Dollars in Millions) | A | | B | | C | | D | |
|---|---|---|---|---|---|---|---|---|
| | Reference Cases | | | | Recommendations | | | |
| | All Gas Case<br>Gas resources and no new transmission additions in Rocky Mountain States | | IRP- Based Case<br>IRP resources and no new transmission additions in Rocky Mountain States (Suppressed Wind) | | Recommendation 1 | | Recommendation 2 | |
| | Initial Investment | Representative Year | Initial Investment | Representative Year | Initial Investment | Representative Year | Initial Investment | Representative Year |
| 1 Production Costs (Fuel & Other VOM) | | 21,018 | | 20,046 | | 19,780 | | 18,458 |
| 2 Change from All Gas Case [Column A] | | - | | (972) | | (1,238) | | (2,560) |
| 3 Change from IRP- Based Case [Column B] | | 972 | | - | | (266) | | (1,588) |
| 4 | | | | | | | | |
| 5 Resource Costs: | | | | | | | | |
| 6 RM Resource Additions Capex | | | | | | | | |
| 7 Wind | | | 1,957 | | 2,246 | | 3,766 | |
| 8 Gas thermal | 2,204 | | 444 | | 198 | | 373 | |
| 9 Coal thermal | | | 3,453 | | 3,985 | | 7,857 | |
| 10 Incremental Transmission Integration Capex | 53 | | 159 | | 175 | | 311 | |
| 11 RM Resource Capex Sub Total | 2,257 | | 6,012 | | 6,604 | | 12,306 | |
| 12 Adj. Outside RM Resource Additions Capex | | | | | | | (2,257) | |
| 13 Other RM Costs | | | | | | | | |
| 14 Incremental Capital Charge @ 10% | | 226 | | 601 | | 660 | | 1,231 |
| 15 Incremental Fixed O&M | | 28 | | 116 | | 128 | | 245 |
| 16 Wind "lease and tax" | | - | | 39 | | 56 | | 94 |
| 17 Subtotal Other RM Costs | | 254 | | 756 | | 845 | | 1,570 |
| 18 Adj. Other Costs Outside RM | | - | | - | | - | | (254) |
| 19 Total Resource Costs | 2,257 | 254 | 6,012 | 756 | 6,604 | 845 | 10,050 | 1,316 |
| 20 | | | | | | | | |
| 21 Transmission Costs: | | | | | | | | |
| 22 Incremental Line Capex | | | | | 777 | | 3,872 | |
| 23 Customized Equipment Capex | | | | | 193 | | 393 | |
| 24 RM Transmission Capex Sub Total | | | | | 970 | | 4,265 | |
| 25 | | | | | | | | |
| 26 Incremental Fixed O&M | | | | | | 19 | | 85 |
| 27 Incremental Capital Charge @ 10% | | | | | 970 | 97 | 4,265 | 427 |
| 28 RM Transmission Costs | | | | | | 116 | | 512 |
| 29 | | | | | | | | |
| 30 Annualized Costs | | 254 | | 756 | | 961 | | 1,828 |
| 31 | | | | | | | | |
| 32 Total Initial Investment | 2,257 | | 6,012 | | 7,574 | | 14,315 | |
| 33 Annual Net (Savings)/Cost from All Gas Case | | - | | (470) | | (531) | | (988) |
| 34 Annual Net (Savings)/Cost from IRP- Based Case | | 470 | | - | | (61) | | (516) |

"Initial investment" amounts are translated into annualized capital charges in the column labeled "Representative Year". The annual capital charge reflects inflation adjusted (real) streams of depreciation, return on capital, property and income taxes, interest, replacements and administrative and general costs over the depreciable life of the asset. This charge is applied as a percentage of the initial investment, and is shown on lines 14 and 27. Fixed O&M costs are then added. The sum of the annualized capital charge and fixed O&M (line 30) is then compared to the annual production cost savings (lines 2-3) to determine annual net savings from the two reference cases (lines 33-34). See Appendix B.8 for a full explanation of the economic comparison table.

This analysis finds that Recommendation 1 would save $531 million annually on a west-wide basis compared to the All-Gas Reference Case and $61 million annually compared to the IRP-Based Reference Case.[5] Recommendation 2 would save $986 million annually compared to the All-Gas Reference Case and $516 million compared to the IRP-Based Reference Case. See Table 3-8, which summarizes the data from lines 33-34 in Table 3-7. As noted in Chapter 2, capital investment amounts for new gas-fired resources do not include the investment that may be required for pipeline compression and expansion. If such investments were required, the savings for Recommendation 1 and 2 could be greater than shown.

*Table 3- 8: Annual Savings Compared to Reference Cases*

*(Savings West-wide for a Representative Year, Millions of Dollars)*

| | Reference Case | |
|---|---|---|
| | **All-Gas Case** | **IRP-Based Case** |
| | | |
| **Recommendation 1** | (531) | (61) |
| | | |
| **Recommendation 2** | (986) | (516) |

An economic comparison of Recommendation 1 and 2 with the Reference Cases, using the low natural gas price sensitivity, produces the results shown in Table 3-8. A persistent, relatively low natural gas price assumption reduces the economic viability of Recommendations 1 and 2. Compared to the IRP-Based Reference Case, the benefits of Recommendation 1 do not appear to justify the required transmission investment. Compared to the All-Gas Case (which assumes heavy reliance on gas-fired plants) the benefits of both Recommendations 1 and 2 remain economic.

Assuming high natural gas prices, the annual savings and net benefits of Recommendations 1 and 2 would be significantly higher than those shown in Table 3-8. Gas price hedging benefits provided by new transmission and low fuel cost resources should be considered, but are not reflected in this study. Strategies to hedge against uncertain – and potentially volatile – natural gas prices are important in providing greater stability in electricity prices.

*Table 3- 9: Annual Savings Compared to Reference Cases-*

*Assuming Low Natural Gas Prices (Savings West-wide for a Representative Year, Million of Dollars)*

| | Reference Case | |
|---|---|---|
| | **All-Gas Case** | **IRP-Based Case** |
| | | |
| **Recommendation 1** | (153) | 7 |
| | | |
| **Recommendation 2** | (221) | (61) |

[5] The savings from the IRP-Based Reference Case may be understated because the IRPs may not include the transmission investment needed to integrate the wind and coal resources they contemplate.

## G. Distribution of Economic Gains and Losses

To advance the development of transmission expansion projects that show economic benefits on an interconnection-wide basis, it is necessary to understand how the economic benefits and losses from the projects are distributed within the West.

Table 3-10 shows the economic benefits (and losses) by region for Recommendations 1 and 2 in comparison with the two reference cases. The benefits (and losses) are categorized as load benefits and generation benefits. The numbers are derived from the production cost simulation and do not include capital and other fixed costs (See Chapter 2 for a discussion of locational marginal prices (LMPs) derived from the model.)

In the simulation, the **Load Benefit** is defined as the reduction in cost to serve regional load, and is derived from the following: hourly demand (MWh) at each load node multiplied by the hourly LMP ($) and summed for the test year 2013.

The simulation defines **Generation Benefit** as the gross generator margin, and is derived from the following: hourly generation (MWh) at each generation node multiplied by the hourly LMP ($) and summed for 2013 (i.e., generator revenue) less annual fuel and other production costs.

The model-generated estimates of benefits and losses assume a real-time competitive market in which pricing is on an hourly, LMP basis. Although California is moving in this direction, such markets do not exist today in the West. For this reason, the actual distribution or sharing of the benefits (and losses) among consumers (i.e., load) and owners of generation in each region will vary from the distribution shown here.

Benefits will flow to consumers when reductions in the cost of serving the load are passed through in retail rates. Benefits shown in the Generation Benefit column will mostly accrue to consumers in retail rates if the generation is owned by a vertically-integrated utility. On the other hand, Generator Benefits (and Losses) will accrue directly to independent power producers and merchant power plant owners to the degree the investment is not imbedded in regulated (or public utility) rate base pursuant to contracts between the generator and the load-serving entity. Depending on the terms of the power purchase contract, Generator Losses may not be in the rate base of LSEs and thus would not be borne by customers. In addition, as explained in Chapter 2, the system simulation includes none of the rate pancaking inefficiencies of the current system. Thus, the benefits and losses shown are in addition to benefits that would result from removing such inefficiencies. For example, northwestern generators would probably benefit on the whole from the removal of rate pancaking, but the losses shown in Table 3-9 do not take this benefit into account.

*Table 3- 10: Economic Benefits and Losses (Millions of Dollars)*

**Recommendation 1 Compared to IRP-Based Reference Case**

| Region | Load Benefit | Generator Benefit | Total Benefits |
|---|---|---|---|
| Rocky Mountain | (5) | 294 | **290** |
| Northwest | 65 | (78) | **(13)** |
| Canada | 20 | (20) | **1** |
| Mexico | 1 | (1) | **0** |
| California | 54 | (110) | **(56)** |
| Desert SW | 8 | (9) | **0** |
| Total | 145 | 77 | **221** |

**Recommendation 1 Compared to All-Gas Reference Case**

| Region | Load Benefit | Generator Benefit | Total Benefits |
|---|---|---|---|
| Rocky Mountain | 123 | 983 | **1,106** |
| Northwest | 128 | (161) | **(32)** |
| Canada | 37 | (35) | **2** |
| Mexico | (1) | 1 | **0** |
| California | 91 | (76) | **14** |
| Desert SW | 0 | 0 | **0** |
| Total | 377 | 712 | **1,090** |

**Recommendation 2 Compared to IRP-Based Reference Case**

| Region | Load Benefit | Generator Benefit | Total Benefits |
|---|---|---|---|
| Rocky Mountain | 750 | 176 | **926** |
| Northwest | 517 | (550) | **(33)** |
| Canada | 207 | (204) | **3** |
| Mexico | 20 | (23) | **(4)** |
| California | 646 | (321) | **326** |
| Desert SW | 286 | (395) | **(109)** |
| Total | 2,427 | (1,318) | **1,109** |

**Recommendation 2 Compared to All-Gas Reference Case**

| Region | Load Benefit | Generator Benefit | Total Benefits |
|---|---|---|---|
| Rocky Mountain | 878 | 864 | **1,742** |
| Northwest | 581 | (633) | **(52)** |
| Canada | 224 | (219) | **4** |
| Mexico | 18 | (22) | **(3)** |
| California | 683 | (287) | **396** |
| Desert SW | 277 | (386) | **(109)** |
| Total | 2,660 | (682) | **1,978** |

The distribution of gains and losses shows annual benefits to the Rocky Mountain region ranging from $290 million to over $1.106 billion, compared to the two reference cases. These benefits come with little net impact on western regions outside the Rocky Mountain States. This makes a compelling case for entities in the Rocky Mountain States to work together to build this transmission and capture the economic gain. Chapters 4 and 5 address some of the challenging issues that will need to be addressed in Phase II to accomplish this.

The gains and losses comparisons for Recommendation 2 demonstrate that developing and exporting coal and wind generation from the Rocky Mountain region will benefit consumers in the Western Interconnection. Using the assumptions in this screening analysis, total west-wide consumer benefits range from $2.427 to $2.66 billion annually. In many parts of the West, load (i.e., consumer) benefits are roughly offset by generator losses. Such generator loses may or may not be passed on to consumers. The notable exception here is California. Even net of generation losses, California stands to gain between $326 and $396 million per year if Recommendation 2 is built. Benefits to the Rocky Mountain region also increase with Recommendation 2 by over $600 million per year, compared to Recommendation 1, and range from $926 million to $1.742 billion annually. The Rocky Mountain states should invite California to participate in future work pursuant to Recommendation 2. This and other Phase II efforts are discussed further in Chapters 4 and 5.

## H. Conclusions

The economic screening study in RMATS Phase I finds that the transmission recommendations provide economic benefits over a reasonable range of future natural gas prices and hydro conditions. Significant benefits to the Rocky Mountain region appear attainable if the transmission projects in Recommendation 1 are constructed, enabling the region to increase its reliance on low fuel cost coal and wind resources rather than on new gas-fired generation. Recommendation 2 produces significant consumer benefits throughout the West, with strong beneficiaries in the Rocky Mountain region and in California.

Future natural gas prices are the largest driver of the production costs. If a relatively low natural gas price future persists, Recommendation 1 does not appear to be economic. This conclusion ignores the benefits of hedging against uncertain future natural gas prices, which these transmission expansions would provide.

Several conclusions can be drawn from the economic analysis of the Recommendations 1 and 2:

- The Rocky Mountain region would benefit significantly if coal-fired and wind resource development is given priority over gas-fired resource development to meet its load growth.
- Substantial increases in natural gas demand – driven in large part to gas-fired electric generators – has led to natural gas price escalation and volatility, making fuel diversification an increasingly important priority for LSEs throughout the West.
- Given its abundant reserves of low-cost fuels, the Rocky Mountain region is well positioned to contribute to the West's fuel diversification goals – if the West supports the necessary transmission expansion.
- Diversification into new Rocky Mountain coal and wind generation reduces production costs throughout the West when compared to natural gas-fired generation. The Rocky Mountain states and West Coast markets (California markets in particular) stand to benefit.

# APPENDIX A-5-F

# Chapter 4 - Cost Allocation and Cost Recovery Issues

## A. Introduction

RMATS has identified and recommended potential upgrades and expansions to the transmission system in nine western states.[1] The economic analysis shows these projects could produce lower costs to the extent the lower production costs are translated into lower wholesale prices throughout the Western Interconnection. Phase II of RMATS will focus on potential mechanisms to make the RMATS recommendations financially viable by addressing cost allocation and cost recovery.

This chapter is organized in six sections:

- A problem statement explaining the regulatory uncertainty that surrounds transmission and other factors that have affected transmission investment;
- A brief summary of previous recommendations to the Western Governors and by the Federal Energy Regulatory Commission (FERC);
- An overview of the importance of existing regulatory practices associated with transmission cost allocation and cost recovery;
- Proposed transmission expansion cost allocation principles;
- Specific recommendations for how to proceed in Phase II; and
- Project-by-project suggestions on a starting point to consider participation and financing of the transmission expansions.

The recommendations herein represent the broad consensus of the RMATS participants, and are respectfully offered to the sponsoring governors, state and federal regulators and potential project participants for their consideration and implementation.

## B. Problem Statement

Investment in new transmission infrastructure in the West has lagged behind the growth in both demand and new generation. There have been very few new bulk power transmission infrastructure additions in the western interconnection in over a decade. With low gas prices throughout the 1990s, most additional generation has been gas-fired, located close to load, requiring little additional transmission capacity. New transmission capacity that has been added has been devoted primarily to maintaining local reliability, particularly in the Pacific Northwest and Arizona, or accommodating the gas-fired generation interconnections in various locations.

Regulatory uncertainty, arising from questions about recovering the cost of transmission investments and the impact of FERC's push toward open access to the transmission system with the issuance of Order Nos. 888 and 889 beginning in 1996, is a major reason for the lack of recent transmission investment. These and subsequent FERC orders have begun the process of decoupling what has historically been an economic and operational link between investment in new generation and new transmission infrastructure. This decoupling allowed other generators to compete to serve load of the host utility. Prior to the advent of transmission open access, entities responsible for serving native loads planned generation and transmission investments in tandem with the expectation that such investments, since they were devoted to serving native load

[1] Three incremental upgrades included in Recommendation 1 could involve Colorado, Idaho, Montana, Utah and Wyoming. Long-term recommendations for exports from the RMATS region are also presented for projects that could involve states outside the RMATS region, including California, Oregon, Nevada and Washington.

customers, would provide the least cost means to serve customers and be recovered through the retail rates paid by those customers. Under open access, transmission owners are required, subject to contractual rights and capacity availability, to make excess capacity on their transmission systems available to third party users. Revenues from these services reduce the rates paid by native load customers.

Historically, state regulators, who have exclusive authority to set retail rates, have allowed 100% of the cost of transmission investments for state-jurisdictional transmission owners to be included in the cost of service for native load customers. Any revenue that is generated through the use of the system by third parties has typically been credited against the revenues required from the native load customers.

State jurisdictional transmission owners who invest in new transmission capacity at the request of a third party, per FERC Order No. 888, may experience additional risk of cost recovery to the extent that revenues from the third party are insufficient to cover the cost of the requested capacity addition. Depending on the rate treatment adopted, the transmission owners, shareholders or customers bear this risk. This risk is a barrier to investment in transmission.

Federal policy also encourages formation of RTOs in order to remedy undue discrimination in the use of transmission facilities. With an RTO, transmission owners could voluntarily turn over operation of their transmission to an entity that would have the ability to determine the beneficiaries of new infrastructure development and assist in identifying and implementing appropriate cost recovery approaches. For the utilities that join an RTO, much of the uncertainty regarding the rights and cost recovery associated with new transmission investment could be eliminated.

As a result of these factors and developments, the transmission grid is increasingly regional in nature, with a corresponding increase in the interdependency of transmission owners in the region. This interdependency adds to the uncertainty regarding the rights to control and operate the assets of transmission owners, creating an additional barrier to new transmission investment. This uncertainty will persist in the West until state and federal policies on RTO formation are reconciled.

Power on the Western Interconnection does not necessarily flow over the path on which it is scheduled but instead flows according to the laws of physics and follows the path of least resistance. These unscheduled power flows, or "loop flows," as they are often called, are difficult to predict. Power flows also change over time as loads and resources across the system evolve. These factors introduce uncertainty about the amount of physical capacity that will be available at any given time and can affect virtually every transmission path in the Western Interconnection

The increasingly regional nature of the grid resulting from open access adds uncertainty in the decisions that transmission investors must make. This is especially true for transmission investments that would provide widespread benefits to consumers in multiple state jurisdictions. It is this uncertainty that the recommendations in this chapter are meant to address. Establishing regulatory clarity on assigning and recovering costs will help to enable the financing of projects by regulated utilities and merchant transmission entities. The regulatory uncertainty associated with new transmission investments, including specific examples and potential strategies to mitigate that uncertainty, are described in greater detail in the remaining sections of this chapter.

Another impediment to transmission investment is the traditional regulatory practice of accounting accruals for capital investments as AFUDC[2] during the time when construction work is in progress. These funds are accounted for, with interest, and only included in regulated rates after a plant investment is in service and a prudency determination has been made. This means that for investments that have long construction time-frames, such as transmission expansions and coal plants, there is a significant cash flow and no allowed rate of return on investment for multiple years. In contrast, investing in natural gas-fired plants located in proximity to loads can be put into service relatively quickly and with lower capital requirements, minimizing both cash flow requirements and the period of time these outlays do not produce a rate of return.

The lack of transmission investment to enable consumers access to lower cost coal and wind resources is an increasing concern because without transmission investment the region will, by default, become increasingly reliant on natural gas-fired resources located close to load, with the attendant exposure to high and volatile natural gas prices.

### C. Past Recommendations to Western Governors and from FERC

Transmission investment (capital and operating) costs can be directly assigned to market participants, such as generation developers or loads – this is referred to as *participant funding.* It can also be recovered through retail electric rates across the broader system (or a subset of the system), which is commonly referred to as *rolled-in* ratemaking.

A report to the Western Governors in February 2002[3] discussed the need for regulatory certainty to finance transmission expansion, and described the pros and cons of the participant funding and rolled-in models in some detail. While recognizing these two cost responsibility philosophies are not necessarily mutually exclusive, the report did not explore any hybrid possibilities.

Among the recommendations in the report to the Governors in 2002 was the following:

> *3.b. The Governors should urge FERC and state Public Utility Commissions (PUCs) to form joint State/FERC panels to adopt appropriate mechanisms that will enable cost recovery of transmission investments made before the RTO structures are fully implemented. Working in conjunction with SSG-WI, these panels could drive agreements between state and federal regulators, transmission developers and their investors that would provide cost recovery assurances sufficient to induce development of needed infrastructure. The panels should also explicitly consider risks and the need for financing incentives.*[4]

RMATS Phase I has defined specific potential transmission expansions. Phase II will be an approach similar to the process recommended to the Western Governors, focusing on specific projects that have demonstrated value in the RMATS study.

In the April 28, 2003 White Paper on Wholesale Power Market Platform, FERC stated:

> *We will look to the RTO or ISO and the regional state committee to determine the appropriate regional approach for allocating the costs of new transmission. Regions may differ on the extent to which they want to rely on participant funded expansions; this difference need not create "seams" with neighboring regions. Because this issue is such an important one in stimulating appropriate investment by both existing and new*

[2] Allowance for Funds Used During Construction
[3] Financing Electricity Transmission Expansion in the West, February 2002.
[4] Ibid, at p. 4.

*transmission companies, we will allow an RTO or ISO to implement such policies once there is a regional planning process through which an independent entity performs all necessary facilities studies and determines cost responsibility for the required transmission upgrades.*

While the RMATS region does not have an RTO or an ISO, FERC may consider projects and the allocation of costs and rights recommended by the RMATS process because it is a regional planning process that is independent of any one utility. It seems that FERC would seriously consider any cost allocation and pricing proposal that would have acceptance by state regulators, utilities, generators, and customer advocates within the RMATS region.

Regional solutions for transmission system expansion and pricing are encouraged by FERC. Further, state regulators look favorably upon regional solutions to the extent that regional solutions are shown to be cost effective for their constituents.

### D. The Importance of State and Federal Ratemaking Practices

Presently state (retail) and federal (wholesale) ratemaking consists of two independent processes. Retail rates and regulation fall under the exclusive domain of the state regulatory commissions and transmission and wholesale power rates are under the federal jurisdiction. This bifurcated regulatory system can and will have a profound effect on the ability to obtain financing and cost recovery on any new transmission, and must be understood and addressed in order to facilitate the RMATS transmission recommendations.

FERC consists of up to five commissioners who are appointed by the President of the United States. FERC has absolute jurisdiction over wholesale electric rates, both transmission and wholesale sales. The state regulatory commissions in Colorado, Idaho, Utah and Wyoming consist of three commissioners appointed by their respective Governors. In Montana there are five elected commissioners. The state commissions have exclusive jurisdiction over bundled retail rates. A component of rates paid by retail customers is transmission-related costs that can face both state and FERC jurisdiction.

Electric utilities fall into one of two broad categories: jurisdictional and non-jurisdictional. Jurisdictional utilities are typically the investor-owned utilities, such as PacifiCorp, Idaho Power Company, Northwestern Energy (NWE) and Xcel Energy, which are subject to both state and FERC regulation. Merchant power and transmission companies fall under FERC jurisdiction. Federal Power Marketing Administrations, such as the Bonneville Power Administration (BPA) and the Western Area Power Administration (WAPA) and most public utility districts, municipalities, cooperatives and rural electrification associations are non-jurisdictional to FERC and state commissions. However, many non-jurisdictional entities abide by FERC rules, either voluntarily or under reciprocity provisions.

Transmission expansions constructed by jurisdictional companies that have no retail load are regulated exclusively by FERC. Revenues for these entities are dependent entirely on wholesale users of its transmission system.

This section does not focus on issues associated with construction and expansion of transmission by non-jurisdictional utilities. Non-jurisdictional utilities have the ability to design their rates in more flexible ways. However, even projects that are sponsored by non-jurisdictional utilities may involve commercial arrangements with state jurisdictional utilities and be subject to state regulatory review. In some cases, state regulatory review is required for non-jurisdictional utilities.

### State Regulation

State regulators have jurisdiction over retail rates and tariffs and are usually involved in four major areas: planning, construction, siting and cost recovery.

The planning process typically involves an Integrated Resources Plan (IRP)[5]. An IRP typically involves a stakeholder process that includes a stakeholders process and a plan that identifies how a particular utility will serve future load growth. If utilities are to be involved in a transmission expansion identified by RMATS, an important step will likely be consideration of the expansion as an element of each utility's resource planning process.

State regulators become involved in construction through the issuance of a Certificate of Public Convenience and Necessity (CPCN). The purpose of a CPCN is to ensure that the construction of the project is required and will not impair the electric consumers of the state now or in the future. CPCNs, if required, must be sought by jurisdictional and, in some cases, non-jurisdictional entities.

Siting of new transmission facilities is also regulated and may require municipal, county, state, federal and Tribal Nation approvals. Please refer to Chapter 5 for more discussion on siting.

Cost recovery is accomplished through rate cases that are submitted by jurisdictional utilities to the commissions in each state. Generally, each state has its own process independent of the other states. Multi-state jurisdictional utilities must submit rate cases in each state. These state rate cases occur after an investment becomes operational, with typically five to seven years of siting and construction outlays in the case of a large transmission investment.

Jurisdictional utilities are likely to be involved in the future development of any new transmission recommended by RMATS. Therefore, RMATS has included state regulators in the process and has attempted to develop information in the screening studies to facilitate state regulatory review of the recommendations.

### FERC Regulation

FERC has exclusive jurisdiction over wholesale transactions, both rates and tariffs, for transmission facilities. FERC has developed a seven-factor test to differentiate transmission facilities from local distribution facilities. In the case of transmission, FERC is committed to wholesale competition as the best means to achieving the lowest possible wholesale power prices. To this end, FERC has been on a steady course to encourage the independent operation of the transmission system through RTOs. FERC encourages RTOs as a means to ensure open access and to promote regional planning and elimination of transmission rate pancaking (paying multiple wheeling charges for a path). FERC also encourages the formation of RTOs as a means to enable an independent entity to implement the outcome of regional infrastructure planning, both in terms of siting and cost recovery.

FERC has encouraged performance-based regulation proposals and indicated that it would consider other innovative transmission pricing proposals such as a higher return on equity than previously allowed, levelized rates, accelerated depreciation and incremental pricing for new transmission investments in order to stimulate new transmission construction.

[5] Integrated Resource Plans are also commonly referred to as Least Cost Plans. For purposes here, IRPs and LCPs refer to the same planning activity.

FERC has expressed interest in, and support of, the RMATS process. FERC staff has participated in the study to ensure that RMATS recommendations to facilitate new transmission development are consistent with, and based in part on, FERC's policies.

**Cost of Service Methodology**

While there are many ways to set rates, the most common and widely used method is Cost of Service (COS) ratemaking. It is utilized by FERC and almost every state jurisdiction. The basic equation for COS ratemaking is:

(Allowed Rate of Return * Capital Rate Base) + Expenses + Taxes + Depreciation = COS.

There are often adjustments made to the inputs of this equation to reflect the effect of specific events such as mergers, historical disallowances, weather variations, etc. The COS is then allocated over billing determinates that typically include energy consumption and peak demand.

The RMATS recommendations for cost allocation and cost recovery are based on COS concepts. See Appendix G for several simplified examples of how the cost of service methodology could apply to a transmission expansion investment, depending on the circumstances.

During the course development of the RMATS recommendations, attention was given to the dual state and federal regulatory responsibilities for cost allocation and cost recovery. Recommendations for Phase II activities to facilitate new transmission development were based, in part, on the principles discussed below.

**E. Proposed Transmission Expansion Allocation Principles**

RMATS recommends the state PUCs work together to employ a common approach to allocating transmission expansion costs across companies and states. The existing institutional and regulatory structure is the starting point, and the driving principle should be that costs be allocated on bases proportional to benefits and transmission rights received ("beneficiary pays"). To begin implementing this principle, the RMATS study produced estimates of the potential benefits by region. The goal is to allocate the costs of facilities based on the nature and purpose of the investment and the level of use by various customers. This approach is generally consistent with current practice. However, federal and state regulators and potential project participants may also want to look to new ways of cost allocation and regulatory assurance, if necessary to make projects viable.

Cost allocations should:

- Reflect clear, transparent and verifiable criteria and methods;
- Encourage proper investment (protect reliability and support wholesale markets insofar as this lowers retail rates);
- Ensure timely recovery of all prudently incurred costs;
- Enable nondiscriminatory, fair and equitable pricing;
- Take into account the multiple measurable benefits of a facility over its full life; and
- Minimize process burden and avoid contention while ensuring due process.

These principles could be implemented by an operational RTO, however this institution is lacking in the RMATS region. In the absence of an RTO, implementation of these principles will require

strong analytics and a clear process for identifying cost responsibility and assigning rights, and coordination among project participants, their respective states, FERC, and stakeholders. A broad consensus among PUCs, project participants and other stakeholders, and strong political leadership will be critically important.

The RMATS study and recommendations focus on economic upgrades.[6] As such, the options for participation focus on market participants funding projects using a beneficiary-pays allocation mechanism.

Market participants should be given first opportunity to finance the projects identified by RMATS. Participant funding refers to payment for transmission capital requirements by entities that request, require or voluntarily undertake to pay for new transmission. Participants who provide capital for network upgrades would receive a return of the capital, with interest over a defined period of years, as a credit against the participant's transmission rate, once it begins to take service.[7] Facilities that would always be funded directly by participants include generator interconnection-related facilities and merchant transmission facilities.

To the degree that participant funding is not forthcoming for reliability or regionally economic investments where benefits are widely diffuse, a regional rolled in method for allocating costs to customers could apply. Under this allocation method, the cost of transmission facilities (net of any participant funding) could be assigned to utilities by state based on their proportional share of loads. Such costs would then be recovered through the companies' wholesale and retail rates, through the existing regulatory process.

In the case of some facilities, a targeted or "zonal" rolled-in method could be used if the reliability or economic benefits are more localized. These include radials to load connection points, portions of looped switch gear, lower voltage upgrades and higher voltage transmission when it is shown that only one entity benefits.

### F. Recommendations for Phase II Actions

As the Western U.S. tries to meet its growing loads in an era of rising natural gas prices, Rocky Mountain coal and wind resources will look increasingly attractive. The RMATS recommendations are economic transmission expansions that could support increased reliance on coal and wind resources. Phase II of the RMATS process will address barriers to financing and cost recovery that may hinder timely development of these transmission projects when and if they are needed to serve customer needs.

The Rocky Mountain grid is operated by multiple control areas according to reliability criteria developed by the Western Electricity Coordinating Council and the North American Electric Reliability Council. At present, there is no RMATS regional pooling arrangement, independent

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[6] Transmission upgrades can be categorized as follows:

- *Reliability upgrades* are defined as transmission investment necessary to provide acceptable stability response, short circuit capacity and system voltage levels. Reliability upgrades also include facilities required to provide adequate thermal capability and local voltage levels that will probably not otherwise be achieved.
- *Economic upgrades* are defined as transmission investment that provides net economic benefits to the region, as determined in RMATS. These include facilities that do more than interconnect a generator, and that are designed to reduce bulk power costs in the Rocky Mountain states and, in the case of export paths, in West Coast and Southwest markets.

[7] Credits are provided for in FERC's generation interconnection rule, Order No. 2003.

system operator or manager, and there is no single transmission tariff. Further, there is no regional decision-making body in place to govern cost allocation decisions that span multiple states and companies.

A regional RTO could develop over time to remedy the balkanized nature of western transmission operation and planning. For example, Grid West is continuing to pursue agreement with regional participants on a phased approach to implementation. However, for the next several years and for purposes of this RMATS process, we must assume no operating RTO exists and will examine alternative means to cost allocation and recovery of specific, desirable projects.[8]

RMATS provides the following specific recommendations on how to proceed. The recommendations are submitted to the region's Governors, regulators, potential project participants and others for their consideration and implementation.

**Pursue Financial Participation and Regulatory Recovery of Recommended Transmission Upgrades on a Project-by-Project Basis**

A Phase II focus on developing transmission in the RMATS region should explore options for cost allocations on a project-by-project basis. Phase II should examine creative approaches within the status quo regulatory and institutional framework to move individual projects forward.

Ratemaking treatment at the state and federal level must be consistent to allow the investors in the upgrades to recover their full cost of capital and a reasonable return on this capital, without undue regulatory risk and within a reasonable period of time. To the extent that Phase II is successful in recommending an allocation of the costs and rights to transmission upgrades across the various stakeholders, it can contribute to a basis for consistent regulatory treatment.

### Transmission Recommendation 1

The RMATS transmission projects in Recommendation 1 consist of three discrete expansions: 1) the Montana System Upgrade; 2) the Bridger Expansion Project; and 3) the Wyoming to Colorado Project. As presented in Chapter 3, the distribution of economic gains and losses associated with these three projects fall predominantly on the Rocky Mountain region. Taken together, the consumer benefits in reduced load cost and the incremental generator gross margins are estimated to be in a range from $290 million annually to over $1.1 billion per year for the 2013 test year (see Figure 3-9). This makes a compelling case for entities in the Rocky Mountain region to work together and develop a cost allocation and cost recovery solution within the region, as a means for capturing this benefit.

Because these estimates are based on a market structure model of perfect competition, and are based on the assumption that all prices are set by locational marginal pricing, in order to identify likely project participants, we must infer from this information how these cost savings would be distributed to customers given today's market structure.

### Transmission Recommendation 2

Recommendation 2 consists of five different projects which have been paired together to make four options. The primary purpose of all four options is to construct new transmission lines that would

[8] RMATS solutions to cost allocation and cost recovery could be implemented by Grid-West, if and when it becomes operational.

be able to export an additional 3,900 MW out of the RMATS region to meet needs in the West, particularly California.

These projects could allow Load Serving Entities (LSEs) outside of the RMATS region to diversify fuels, lower generation costs and facilitate the reduction of market power by enabling new generators to develop projects that compete with incumbents in their service territories.

In contrast to Recommendation 1, this recommendation is focused on exporting power into higher-cost markets on the west coast from the Rocky Mountain region. Not surprisingly, consumer benefits are shown to be significant throughout the Western Interconnection. In most areas outside the Rockies, the consumer benefits are approximately offset by reductions in generator gross margins. This may or may not impact owners of the displaced generating resources depending on duration of existing contracts and rate treatment of those plants. The reduction in load cost for California consumers is noteworthy, at over $600 million per year, and appears to outweigh the potential loss of generator gross margin within the State of about $300 million (see Figure 3-12).

The consumer and generator benefits for the RMATS region also increases, compared to Recommendation 1, to within a range of $926 million to over $1.7 billion per year. These results suggest that a thrust of RMATS Phase II should be to coordinate Recommendation 2 with California's transmission planning institutions, as well as with the upcoming cycle of west-wide transmission planning done by SSG-WI. The solution to allocating and recovering costs under Recommendation 2 should include a region broader than the RMATS region, in recognition of the widespread beneficiaries.

**Phase II Initial Step**

As an initial step under Phase II, RMATS recommends, for each of the recommended transmission expansion projects, that the Governors of the states where the line would be sited convene a meeting of their public utility commissioners and CEOs of the entities that will likely benefit from an expansion project for the purpose of: (a) presenting the RMATS findings; (b) urging the beneficiaries to sponsor the project in Phase II; (c) setting in place a process for siting, allocating and recovering project costs and (d) conducting transmission technical studies. Governors should also consider inviting Governors and PUCs of other states outside the geographic scope of the transmission projects that would also benefit.

- For the Montana System Upgrade Project, RMATS recommends that the Governor of Montana convene a meeting of the CEOs of Northwestern Energy, the Bonneville Power Administration, the Montana Public Service Commission, coal and wind power plant developers in Montana, merchant transmission developers and other potential project sponsors and participants.

- For the Bridger Expansion Project, RMATS recommends that the Governors of Idaho, Utah and Wyoming convene a meeting of the CEOs of Idaho Power, PacifiCorp, the Utah Associated Municipal Power Systems, the Utah Municipal Power Authority, the Wyoming Infrastructure Authority, coal and wind power plant developers in Wyoming, the Idaho Public Utilities Commission, the Utah and Wyoming Public Service Commissions, merchant transmission developers and other potential project sponsors and participants.

- For the Wyoming to Colorado Transmission Project, RMATS recommends that the Governors of Colorado and Wyoming convene a meeting of the CEOs of Xcel Energy, PacifiCorp, Black Hills Power, Basin Electric Power Cooperative, Tri-State G&T, theWestern Area Power Administration, City of Colorado Springs, the Platt River Power Authority, the Missouri Basin Power Project, the Colorado Public Utilities Commission, the Wyoming Public Service Commission, and the Wyoming Infrastructure Authority, coal and wind power plant developers in Wyoming and Colorado, merchant transmission developers, and other potential project sponsors and participants.

- For the export project options included in Recommendation 2, RMATS recommends that, depending on the option under consideration, the Governors of the affected states convene a meeting of the interested utilities, regulatory agencies and others.

- For example, if an option enhancing exports to California were being considered, we recommend that the Governors of Utah, Idaho and California convene a meeting including PacifiCorp, the Utah Association of Municipal Power Systems, California investor-owned and municipal utilities, the California ISO, the Utah Public Service Commission and the California Public Utility Commission. The Wyoming Infrastructure Authority should also be involved in meetings associated with Recommendation 1 projects..

**Pursue Improvements in Regulatory Institutions to Enhance Ability for Resolution of Transmission Cost Recovery Issues**

In addition to exploring financial participation and regulatory recovery for the projects in Recommendations 1 and 2, RMATS recommends improvements in existing regulatory institutions. Five specific enhancements are summarized here.

**Develop Multi-State Pricing Principles**

RMATS recommends that the Rocky Mountain states, through their regulatory commissions and after hearings, enter into a memorandum of agreement (MOA) adopting pricing principles, and jointly file such an MOA at FERC and request the Commission's endorsement. These principles would then be used as criteria for decision-making for any applications for transmission cost recovery received by regulatory commissions within the RMATS region, thus providing a degree of clarity and consistency in regulatory treatment. These principles could also be included in tariff filings made by FERC-jurisdictional utilities.

A binding agreement among the commissions should be explored, as well as voluntary approaches to application of pricing principles. RMATS recommends that the pricing principles recently approved by FERC for the Northeast region serve as the model for pricing principles developed by RMATS.

RMATS also recommends exploring means to increase regulatory certainty, including, but not limited to: forms of pre-approval; higher rates of return on transmission investments; and quicker

rate-basing of transmission investments,. In Phase II, a joint stakeholder and regulatory group could be formed to provide a forum for exploring these options.[9]

### Institutionalize RMATS Regional Planning

Transmission planning capability will need to be available to support Phase II activities, including the application of pricing principles to specific projects, evaluating other benefits of transmission projects, such as increased reliability, fuel diversity, and providing input to federal and state regulatory processes.

The RMATS planning function should continue to be coordinated with other sub-regional plans through the broader west-wide planning performed by SSG-WI. Further, if Grid-West becomes operational, the RTO could assume the transmission planning function, and RMATS regional planning could devolve.

### Coordinate Regional Transmission Planning with LSE Resource Plans

To improve regional transmission planning efforts and LSE resource plans, RMATS recommends the (1) the RMATS transmission recommendations be considered in the resource plans of LSEs in the Rocky Mountain region and in the review of such plans by the regulatory commissions in Colorado, Idaho, Montana, Utah and Wyoming; and (2) future RMATS transmission planning build on the most recent resource plans and resource acquisition actions of LSEs in the Rocky Mountain region.

RMATS broke new ground in regional transmission planning by explicitly incorporating the resource plans of Idaho Power Company, PacifiCorp. and Xcel into the analysis of transmission Alternative 1. The development of a "quasi" integrated resource plan for the region (Alternative 2) highlighted potential investments in new generation and transmission that could lower costs compared to existing LSE resource plans. Closer coordination of regional transmission planning with LSE resource plans can improve the quality of both efforts and should be encourages.

### Engage the Wyoming Infrastructure Authority

In the 2004 legislative session, Wyoming enacted a law[10] creating the Wyoming Infrastructure Authority (WIA). The WIA has the authority to own, operate and maintain high-voltage interstate transmission facilities. Within the state of Wyoming, the WIA also has condemnation power to facilitate transmission expansion planning and siting.

The WIA became effective July 1, 2004 and is governed by a five-member board, appointed by the Wyoming governor. To begin its work, the Wyoming legislature appropriated operating funding.

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[9] This approach may not work for the RMATS Recommendation 2, because these export projects implicate a broader geographic footprint than the RMATS region. However, if the pricing principles lead to successful transmission expansions in the Rocky Mountain region, by example this success could lead to broader application of these principles throughout the West. This could be done voluntarily among states, through an organization such as CREPC or as an element of RTO formation.

[10] The engrossed bill, Senate File 52, is available at http://legisweb.state.wy.us

This funding is deemed a loan and the WIA will ultimately be obligated to repay the loan with interest.

The WIA has the authority to issue revenue bonds to raise capital to build transmission infrastructure it would own. There is no statutory limit on this bonding authority for projects the WIA might own. The WIA also has the capability, within an outstanding bond cap of $1 billion, to issue bonds to build transmission facilities owned by other entities. All WIA-issued bonds would be exempt from state taxation. Tax-exempt bond financing may reduce the cost of transmission projects compared to private-sector equity and debt financing.

The WIA is constitutionally barred from issuing revenue bonds backed by the faith and credit of the State of Wyoming. This means for any WIA bond issuance to be successfully received by the financial community, the bonds will likely need to be secured by an expected revenue stream from the transmission investment. This security could take the form of subscription-type contracts with entities expected to use the transmission, a lease agreement with one or more utilities agreeing to take transmission capacity, or other means.

The WIA is a new institution that will become involved in transmission planning and expansion. This creates opportunities to collaborate on transmission investments, to pursue partnerships with public and private entities, to begin to address siting and rights-of-way issues, and to explore creative financing and contracting. These opportunities should be vigorously examined in RMATS Phase II, and should involve the WIA board.

**Pursue More Efficient Ways to Use, Operate and Expand the Transmission System**

The RMATS region is a large subset of the geographic footprint that is the western interconnected system. Grid West, which is under development, would be an RTO covering Washington, Oregon, Nevada, Idaho, Utah, British Columbia and most of Montana and Wyoming. Stakeholders are exploring this option through the Regional Representatives Group and other forums.

A fully operational RTO such as Grid West would be designed to independently operate transmission over this large region, streamline transmission access and pricing, consolidate control areas, and address congestion, planning and expansion of the system. An RTO would have a common tariff and be an institutional means for implementing transmission cost allocation and recovery. It is conceivable that a future RTO in the RMATS region could adopt an approach of transmission expansion costs not unlike the ISO New England model that was recently approved by FERC.

RMATS recommends that Governors and regulators consider the formation of an RTO with features appropriate to the region, including independence and cost-effectiveness. RMATS encourages ongoing efforts to explore formation of Grid West, including its collaborative approach with regional regulators and stakeholders.

RMATS also recommends that the region not wait for Grid West or other RTOs to form and become operational, as the sole means of addressing transmission expansion opportunities in the Rocky Mountain region. To do so risks perpetuating the status quo should the institutional changes not materialize. Such a delay may translate into a lost opportunity to realize consumer benefits from added infrastructure that RMATS has shown to potentially be over $1 billion per year. Accordingly,

RMATS participants strongly believe the region collectively should move forward on these recommendations.

**Strengthen Regional Coordination**

At the direction of Western Governors, CREPC[11] has explored the value of an enhanced regional electricity function among the states and provinces in the Western Interconnection. CREPC examined the value of an enhanced regional electricity function in five areas: reliability; resource adequacy, market monitoring, transmission planning and expansion, and transmission permitting. In March 2004, CREPC found that at this time, the West does not need the formality of an interstate compact, nor is there a need to transfer any state-level authority to a regional body. However, there is an urgent need to enhance the regional electricity function of states and provinces. This requires additional resources for states and provinces to act regionally to: (1) ensure quality analysis of the adequacy of resources to meet demand; (2) enable coordination among the states and FERC on monitoring Western electricity markets; and (3) enable active state participation to advance regional transmission planning and expansion and ensure Governors' policy objectives are addressed. CREPC found that to be successful, any enhanced regional electricity functions need the imprimatur of Western Governors. CREPC also found that:

- Continued progress in pro-active transmission planning is contingent on the voluntary efforts of a few companies and regular engagement of Governors; pro-active planning has not become routine.
- The WGA Transmission Permitting Protocol appears adequate for coordinating permitting reviews of proposed interstate transmission lines, but has not yet been tested because no new interstate transmission line has been proposed since the Protocol was signed in 2002.
- If the pending Federal energy legislation is enacted to establish mandatory reliability standards and grant FERC the power to pre-empt state electric transmission siting laws, then additional action is needed.
    - Governors would need to create an interconnection-wide regional reliability advisory body; and
    - Additional resources would be needed to participate in the federal government's identification and designation of "national interest" transmission lines where state permitting authority would be preempted.

In June 2004, Western Governors accepted CREPC's recommendations, directed that options be developed to finance an enhanced regional electricity function, and requested stakeholder input on the recommendations.

## G. Ownership and Financing Considerations

The transmission expansions in Recommendation 1 include three discrete projects. To a degree, ownership and financing options can be anticipated because the incremental projects add transmission capacity to existing corridors, implicating specific entities with ownership or rights to the existing transmission system. RMATS participants offer the following as a starting point for Phase II discussions among these parties and others. This presentation is in no way intended to

[11] CREPC refers to the Committee on Regional Electric Power Cooperation, an organization that includes the regulatory, energy and facility siting agencies in 12 Western states and two Canadian provinces in the Western Interconnection.

imply that the utilities or other market participants have made any commitments regarding participation or financing of these transmission projects. Nor is this starting point intended to preclude other options that may be taken up by parties in Phase II discussions.

**Montana System Upgrade Project**

The Montana System Upgrade Project would increase the capacity of the existing 500 kV transmission system by an estimated 500 MW. This project consists of increasing series compensation, adding a new transformer and constructing two new substations. This increased capacity would allow the export of new wind and coal resources from Montana to the Pacific Northwest.

Potential customers for this project are LSEs in the Pacific Northwest who could benefit from access to low-cost coal and wind resources. Possible investors are the current transmission owners (Avista, Portland General Electric, PacifiCorp, Puget Sound Energy and Northwestern Energy), BPA, and perhaps independent transmission developers. The ownership structure will likely be joint ownership for the section between Colstrip and Townsend (Ringling) and BPA ownership for the remaining section. The operators of this project are likely to be Northwestern Energy and BPA.

The financial viability of this project will depend on its ability to attract long-term firm commitments from creditworthy counterparties for transmission service. If these counterparties are state-regulated LSEs, then regulatory approval of the transmission agreements may be required to satisfy potential investors in the project. The current bankruptcy of Northwestern should not have an adverse impact on this project assuming that Northwestern emerges from bankruptcy prior to the construction of the project.

While creative ownership and financial structures could be designed for this project, classical balance sheet financing by the current transmission owners who choose to participate is anticipated. Because all current owners, other than BPA, are FERC jurisdictional, favorable treatment by FERC for those entities and favorable treatment by BPA will be necessary. Even though the most likely recovery of investment will be through FERC rates and tariffs, favorable state regulatory treatment for jurisdictional utilities involved will also be required.

If, as expected, the additional capacity facilitates development of new wind and coal resources in eastern Montana by new participants, it may help mitigate generation market power not only in the Pacific Northwest but also in Montana. However, if the incumbent generation owner in the area acquires the additional transmission rights and no new entrants build wind or coal generation, the effect of the additional transmission capacity may be to increase the incumbents' generation market power.

Next steps will require a core group of the market participants noted above to either independently or jointly perform a detailed study of the project. The investor-owned utilities would also need to evaluate the project in the context of their resource plans. Merchant generators will need to secure buyers for their output. Then, the market participants will require approvals for construction as well as regulatory approval of rates. Viability of this project will require that commercial participants be identified and regulatory approval or acknowledgment of IRPs from state commissions.

**Bridger Expansion Project**

The Bridger Expansion Project would increase the ability to move power from Wyoming to Utah and Idaho by 1,350 MW by adding new transmission lines between the Minors substation in Wyoming to the Ben Lomond substation in Utah and between the Bridger plant in Wyoming to the Midpoint substation in Idaho.

The primary purpose of this expansion would be to increase the transfer of low-cost coal and wind resources from Wyoming. This project could increase fuel diversity and reduce generation costs. Although conceptually the project is likely to provide greater reliability, such effects have not been modeled or otherwise quantified. Conceptually, the project may also mitigate generation market power but again this effect has not been studied.

We can identify the current market participants that operate in the relevant area as likely candidates for interest in this project. PacifiCorp and Idaho Power are candidates because they have generators, transmission facilities and service obligations that interconnect with the project, and they are located in the area where significant cost savings are expected to occur. Other market participants that either have generators, transmission facilities or service obligations that interconnect with the project include the merchant coal and wind resource developers in Wyoming, UAMPS, UMPA,[12] Sierra Pacific, Raft River Rural Electric Cooperative and possibly Northwestern Energy. Additionally, the WIA may be interested to the extent this project fits their criteria for funding.

Ownership structures for this project could be joint, individual or segmented depending on which is most efficient. To the extent that the current transmission owners finance this project, it is likely to be balance sheet financed. If the WIA finances a portion of this project that portion is likely to be 100% debt with bond repayment assured by the parties who execute contracts for service with the WIA. A turn-key contract with the WIA may also be a viable alternative to consider.

Next steps will require a core group of the market participants noted above to either independently or jointly perform a detailed study of the project. Utilities that are required to perform IRPs would also need to evaluate the project in that context in order to decide upon their participation in the project. Merchant generators will need to secure buyers for their output. Then, the project participants will require approvals for construction as well as regulatory approval of rates. Viability of this project will require that commercial participants be identified, the WIA's role, if any, be clarified through bond counsel, and regulatory approval or acknowledgment of IRPs from state commissions.

**Wyoming to Colorado Transmission Project**

The Wyoming to Colorado Transmission Project would increase the ability to move power from Wyoming to Colorado by 750 MW by adding a new 345 kV transmission line between the Powder River Basin and just northeast of Denver and adding series compensation. The primary purpose of this expansion would be to allow the delivery of low-cost coal and wind resources from Wyoming to Colorado.

[12] UAMPS and UMPA refer to the Utah Associated Municipal Power Systems and the Utah Municipal Power Agency, respectively.

This project could allow the LSEs in the Colorado Front Range to diversify fuels, lower generation costs, and facilitate the reduction of generation market power by allowing new suppliers to develop projects that compete with incumbents.

The most likely customers for this expansion are the utilities that serve loads in the Front Range of Colorado, such as Xcel, municipal and cooperative utilities served by WAPA, Tri-State and Basin Electric and coal and wind developers. Black Hills Corporation may also have an interest, in light of its pending acquisition of Cheyenne Light and Power from Xcel.

Current owners (WAPA, Tri-State, Xcel, Basin and Wyoming Municipal Power Agency) of the transmission system are likely to be the owners and equity participants in this project. However, this project could also be financed and owned by independent transmission developers or the WIA. Ownership structures for this project could be joint, individual or segmented depending on which is most efficient. To the extent that the current owners finance this project, it is anticipated to be balance sheet financed. If the WIA finances a portion of this project, that portion is likely to be 100% debt with bond repayment assured by the parties who execute contracts for service (or a turn-key contract) with the WIA. Portions of the project that may be funded and owned by WAPA will be subject to federal government budgetary processes.

This project will require approvals for construction as well as regulatory approval of rates. This project will require that the WIA's role, if any, be clarified through bond counsel, and regulatory approvals (pre-approvals if possible) from both state commissions and FERC might be desirable.

Next steps will require a core group of the market participants noted above to either independently or jointly perform a detailed study of the project. Utilities that are required to perform IRPs would also need to evaluate the project in that context in order to evaluate their participation in the project. Merchant generators will need to secure buyers for their output. Then, the market participants will require approvals for construction as well as regulatory approval of rates. Viability of this project will require that commercial participants be identified, the WIA's role, if any, be clarified through bond counsel and regulatory approval or acknowledgment of IRPs from state commissions.

## H. Conclusions

RMATS Phase II should examine, on a project-by-project basis, the level of support for advancing the recommended transmission upgrades. This should be done using available means within the existing regulatory and institutional framework. In addition, the RMATS Phase II should develop a memorandum of agreement among the RMATS states and FERC on specific transmission pricing principles. Additional means to institutionalize RMATS regional planning and improve the existing regulatory framework are also recommended.

# Chapter 5 - Other Important Issues for Transmission Expansion

During the course of the RMATS investigation of potential new transmission additions, several important issues were raised which the Steering Committee felt needed additional analysis and inclusion in the RMATS Report. These were the transmission siting and permitting process, efficient use of the existing transmission system, and new transmission technologies which might be used in the future transmission system.

## A. Transmission Project Review and Permitting Process

Once potential transmission projects have been identified in the planning effort and project sponsors have committed to the development of a project, the project must go through:

- The WECC regional planning process; and
- Siting and permitting processes prior to construction.

### WECC Regional Planning Project Review Process

The sponsor of a major new transmission project (e.g., a project with respect to which the effects are not contained entirely within the sponsoring entity's system) should begin with the WECC Regional Planning Project Review Process which consists of the following process:

- The project sponsor initiates a project review process by letter to the WECC Planning Coordination Committee (PCC) and the Technical Studies Subcommittee (TSS) or the PCC determines that a project has significant regional impacts.
- The project sponsor notifies the PCC of the project purpose and invites stakeholders to join a Regional Planning Review Group (RPRG or Planning Review Group).
- The RPRG prepares to determine the technical merits, costs and feasibility of the stakeholder-defined Project or Project variations.
- The project sponsor submits a Regional Planning Report to the PCC addressing each of the Regional Planning Guidelines and solicites comments. See WECC Procedures for Regional Planning Project Review and Rating Transmission Facilities, Part 1A, Section 1.0.
- Following its review, the PCC issues a separate report outlining conformity of the Project to the Guidelines along with the Project report to RPPC.
- The PCC integrates and submits its assessment and outside stakeholder comments to the project proponents.
- The Regional Planning Project Review Process is completed once a final determination by the PPC is made regarding the project's conformity with the WECC Regional Planning Guidelines, and the Chair of the PCC submits a letter to the Project sponsor, the PCC members and the TSS members indicating that the regional planning process has been completed.
- Refer to the Procedures for Regional Planning Project Review and Rating Transmission Facilities for projects that desire to obtain an "accepted rating".

The fact that the project was developed in the RMATS planning process, with input from all interested parties, should significantly reduce the time it takes to comply with the WECC process.

**Siting and Permitting**

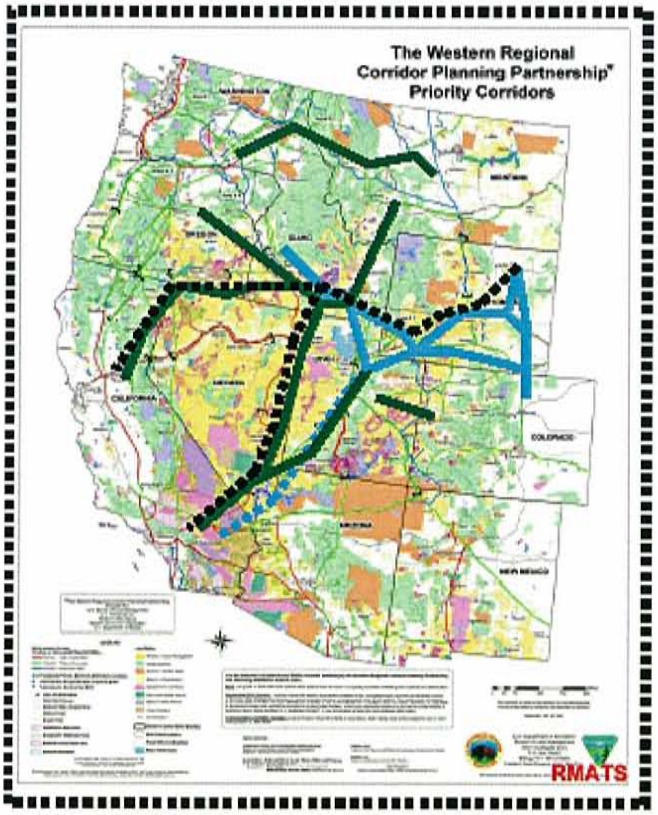
The construction of new transmission will require securing necessary permits from local, state and federal agencies, and potentially Indian Nations. Most of the transmission projects identified in the study will cross federal lands. Historically, securing necessary rights-of-way across federal lands has been among the more challenging aspects of transmission permitting in the western United States.

The Bureau of Land Management (BLM) and U.S. Forest Service are working to expedite permitting of transmission facilities across federal lands through the designation of land use corridors. If new transmission facilities are located in designated corridors the environmental analysis associated with the granting of a right-of-way can be minimized. The Western Utility Group (WUG) is providing advice to the BLM and the Forest Service on the potential designation of utility corridors. Figure 5-1 shows federal land ownership in the West and the WUG's recommendations on corridor designation. The BLM is comparing the WUG recommendations with current land uses.

*Figure 5- 1: Federal Lands and Western Utility Group Corridor Recommendations*

RMATS Transmission
Export Options

Two of the five green lines (500 kV) are required to move the 3900 MW of new resources that are designed for export. One of the two 500 kV-DC lines (black-dotted) is required if an additional 3900 MW of resources are added.




The TAWG benefited from the participation of the BLM during their identification of the routes of new transmission. Efforts were made to avoid locating new transmission in areas with land use restrictions such as national parks, wilderness areas, and areas of critical environmental concern.

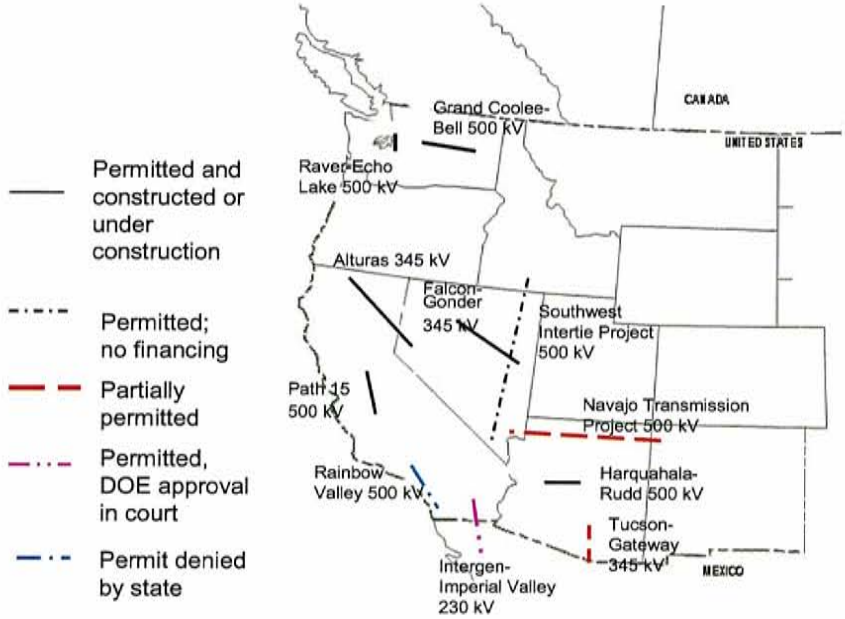
Although this will simplify the process, project sponsors will need to complete substantial additional work on the location of new transmission facilities.

Each of the states in the Western Interconnection, the Province of Alberta, and four federal agencies (Department of the Interior, Department of Agriculture, Department of Energy, the Council on Environmental Quality) have signed the Western Governors Association Transmission Permitting Protocol. This Protocol, which applies to new proposed interstate transmission lines, provides for the collaborative review of proposed transmission projects by permitting agencies. Under the Protocol, project teams would be formed consisting of the agencies with responsibility for issuing permits for a project. The project team will promote the sharing of information and analysis related to the proposed project, establish common deadlines where possible, establish common deadlines, develop information necessary for agencies to make any require determination related to the need for the project, and coordinate data requests of the applicant.

The Protocol, which was initially signed in 2002, has not yet been tested because no new interstate transmission lines have been proposed. However, the expectation is that the Protocol will provide for a more expeditious review of interstate transmission proposals and minimize the typical sequential agency review of transmission project proposals. See the Protocol on the web at http://www.westgov.org/wieb/electric/Transmission%20Protocol/index.htm. Many of the recommended RMATS projects are interstate in nature and, at the discretion of the governors of the states involved, can trigger the Protocol.

Figure 5-2 shows the status of transmission projects of 345 kV and higher that have entered the permitting process in recent years.

*Figure 5- 2: Status of Recent Transmission Proposal 345 and Above*




RMATS intends to collaborate with the National Council on Electricity Policy to develop a workshop on transmission siting in the Intermountain West.

For an illustration of federal agency permitting requirements that may apply to a proposed transmission line, see Appendix C3a. State permit requirements and processes vary by state. See http://www.westgov.org/wieb/electric/Transmission%20Protocol/index.htm for an overview of state permitting laws and regulations in Western states.

**Rocky Mountain State Siting Requirements**

***COLORADO***

**Summary/Overview**

There is no single governmental agency in Colorado responsible for transmission facility siting, and local governments have siting authority for transmission lines. A regulated utility seeking to build a transmission line is required to obtain a certificate of public convenience and necessity (CPNC) from the Colorado Public Utilities Commission (PUC).

Local governments have primary siting authority for power plants in Colorado. Non-utility builders of power plants in Colorado are not required to obtain approval for construction from the PUC. A regulated utility seeking to build a power plant, however, is required to obtain a CPCN from the PUC.

The PUC has a role if the non-utility builder of new power plant wishes to sell any electricity produced by the plant to a utility regulated by the PUC, and its Least Cost Planning (LCP) rules require regulated investor-owned utilities to acquire resources through a competitive resource acquisition process.

**Transmission Certificates of Public Convenience and Necessity**

According to Colorado PUC Rule 4, CCR 723-3-18, each Colorado electric utility is required to annually file information concerning any proposed new construction or extensions of transmission projects for the next three calendar years. The PUC then determines which projects are not required to obtain a CPCN and those for which it must file an application for a CPCN Utilities are required to address the concept of prudent avoidance with respect to the planning, siting, construction, and operation of transmission facilities. Prudent avoidance means striking a balance between potential health effects of exposure to magnetic fields and the cost and impacts of mitigation of such exposure.

**Recent Colorado PUC interstate transmission project approvals**

In 2001, the PUC granted Public Service Company of Colorado (PSCo) a certificate of public convenience and necessity to construct a 345 kV transmission line from Lamar, Colorado to the Colorado-Kansas border and to install a high voltage direct current converter at Lamar. This transmission line would connect the asynchronous transmission grids of the Eastern interconnection and the Western Interconnection. During 2001, the PUC also granted Tri-State Generation and Transmission Association a certificate to construct a new 230 kV transmission line between southwestern Colorado and northeastern New Mexico. The PUC approved a number of transmission projects for PSCo aimed at increasing the reliability of electric service within Colorado, especially in the Denver-Boulder areas.

**Appeal of local government siting decisions**
According to Colorado Revised Statutes (C.R.S.) §29-20-108, a public utility may, under certain circumstances, appeal a local government land use decision concerning transmission lines to the PUC. In undertaking an appeal, the utility must show the reasons why the local government action would unreasonably impair the ability of a public utility or power authority to provide safe, reliable, and economical service to the public.

**Eminent Domain**
The process under which a utility can appropriate public land for the public use by the exercise of eminent domain is described beginning at §38-3-101 C.R.S. The right of eminent domain is exercised by presenting a petition in district court of each county. The process under which a utility exercises eminent domain over private lands is described at §38-5-105 C.R.S.

**Recent major transmission projects**
In 2001, the Colorado PUC approved two interstate transmission projects. The PUC granted Public Service Company of Colorado, a CPCN to construct a 345 kV transmission line from Lamar, Colorado to the Colorado-Kansas state line and to install a HVDC converter at Lamar. This line would provide a connection between the Eastern and Western Interconnections. Tri-State Generation and Transmission Association received a CPCN to construct a new 230 kV transmission line between southwestern Colorado and northeastern New Mexico. The PUC has also approved a number of transmission projects aimed at increasing reliability within Colorado, especially the Denver-Boulder area.

## *IDAHO*

The siting of electric transmission lines in Idaho is not centralized in one government entity. The Governor's Office is the point of contact for coordinating the siting and review of transmission facilities.

**Utility Regulation**
The Idaho Public Utilities Commission has jurisdiction over transmission lines being built by public utilities, exercised through a certification process. See *Idaho Code* § 61-526. Utilities may not need to obtain a certificate of public convenience and necessity if they are merely extending a transmission line within their authorized service territories so long as the new lines do not interfere with the operation of any other utility line. *Id.*

**Eminent Domain/Right-of-Ways**
State law provides that utilities and others may exercise the right of eminent domain to acquire right-of-ways under *Idaho Code* § 7-701(11). For a transmission line of 230 kV or higher to be constructed over private property actively devoted agriculture, requires a public meeting regarding the transmission line's location. *Idaho Code* § 7-704(4). In addition, Idaho law provides that transmission lines may be constructed along or over any public roads except within incorporated cities so long as such lines do not inconvenience the public use of the roadway. *Idaho Code* § 62-705.

**Counties/Cities**
County and city siting requirements varies. Idaho's Land Use Planning Act requires that county and city planning and zoning commissions adopt a "Comprehensive Plan" that includes an analysis of "utility transmission corridors." *Idaho Code* § 67-6508(h). Persons wishing to construct transmission lines should contact the County/City Planner in the affected areas to discuss the necessary

permitting requirements. Compliance with utility right-of-way regulations, subdivision regulations and appropriate use in zoned areas are among the subjects to discuss. Some counties and cities will have additional informational requirements. Cities are also authorized to regulate the construction of transmission lines within city limits. *Idaho Code* § 50-328.

**Environmental Permitting**

Entities constructing transmission lines would seek air, water, and wastewater permits from the Idaho Department of Environmental Quality as appropriate for the specific construction project location.

***MONTANA***

**Siting**

Montana's transmission siting process is centralized in the Department of Environmental Quality (DEQ) under the Major Facility Siting Act of 2003 (the MFSA, § 75-20-101, *et seq.*, MCA), which consolidates most permitting functions into a single process. Under the MFSA, a large transmission line may not be constructed or operated in Montana without a Certificate of Compatibility issued by the DEQ. The MFSA process considers environmental resources, socioeconomic impacts, and costs; provides for public input; and provides a coordinated method for processing all authorizations needed for regulated facilities.

**Lines Covered by the MFSA and Exceptions**

Transmission lines are covered by the MFSA if they have a design capacity of more than 69 KV, except for 1) lines 230 KV or less which are 10 miles or less in length, 2) lines of less than 230 KV if the person planning to construct it has obtained right-of-way agreements or options from more than 75% of the owners who collectively own more than 75% of the property along the centerline that follow public notification procedures; and 3) lines less than 150 miles long which extend from an electrical generation facility, as defined in 15-24-3001(4), MCA, to the point of connection to a regional transmission grid at an existing substation or other facility for which the person planning to construct the line has obtained right-of-way agreements or options for a right-of-way from more than 75% of the owners who collectively own more than 75% of the property along the centerline.

**Required Findings Prior to Construction**

Before it can issue a Certificate of Compatibility, the DEQ must make a number of findings and determinations in a public process about the need for the line, probable environmental impacts and how they are minimized, considering available technology and the nature and economics of alternatives. Regarding transmission lines, other determinations include

*(a.)* what part, if any, of the line or aqueduct will be located underground;

*(b.) that the facility is consistent with regional plans for expansion of the appropriate grid of the utility systems serving the state and interconnected utility systems*; and

*(c.) that the facility will serve the interests of utility system economy and reliability.*

The DEQ must also find:

*(a.)* that the location of the facility as proposed conforms to applicable state and local laws and regulations, except that the department may refuse to apply any local law or regulation if it finds that, as applied to the proposed facility, the law or regulation is unreasonably restrictive in view of the existing technology, of factors of cost or economics, or of the needs of consumers, whether located inside or outside the directly affected government subdivisions;

*(b.)* that the facility will serve the public interest, convenience, and necessity;

*(c.)* that the department or board has issued any necessary air or water quality decision, opinion, order, certification, or permit as required by 75-20-216(3), MCA; and

*(d.)* that the use of public lands for location of the facility was evaluated and public lands were selected whenever their use is as economically practicable as the use of private lands.

**Appeals and Other Laws**

Appeals to the Board of Environmental Review may be taken within 30 days. Local governments may not override a Certificate issued by DEQ under MFSA ; but, when lines are excluded from regulation under MFSA, other state and local laws that would have been preempted by the MFSA would apply. In any case, a project sponsor must obtain easements or permits to cross any school trust, highway, park or other land owned by the State of Montana.

**Eminent Domain**

State law provides that utilities and others may exercise eminent domain authority under Title 75, Chapter 30, Montana Codes Annotated (http://data.opi.state.mt.us/bills/mca_toc/70_30.htm). If a project sponsor must condemn land for a transmission line, the court could not consider any location for the line except the one for which a Certificate of Compatibility was issued under the MFSA.

***UTAH***

**Summary/Overview:**

There is no single Utah State government agency with primary responsibility for transmission facility siting. Various agencies need to be contacted to determine the necessary requirements for the specific proposed project.

Construction of new generation and transmission facilities generally requires receipt of a CPCN from the Utah Public Service Commission although there are exceptions to this requirement. Federal agency permitting is important in Utah, as 65 percent of the land is under federal ownership.

Public utilities can exercise the power of eminent domain pursuant to the requirements of UCA 78-34-1(8).

The last major transmission project constructed in Utah was the Sigurd-Red Butte-Nevada Border 345 kV line which became operational in July 1990 Following a Utah Power and Light request on September 25, 1987, the Commission granted a certificate of convenience and necessity for the line on December 1, 1987.

**Certificate of Convenience and Necessity.**

The Utah Public Service Commission has jurisdiction over the construction and operation of electric facilities. In accordance with Utah Code Ann. § 54-4-25, PacifiCorp "may not establish, or begin construction or operation of a line, route, plant or system, without having first obtained from the commission a certificate that present or future public convenience and necessity does or will require the construction." The foregoing requirement to obtain a certificate is not required for an extension:

a. within any city or town within which it has lawfully commenced operations;
b. into territory, either within or without a city or town, contiguous to its line, plant, or system that is not served by a public utility of like character; or

c. within or to territory already served by it, necessary in the ordinary course of its business.

Challenges may be brought by any other public utility claiming to be injuriously effected by the new facilities. The affected utility is required to file a complaint with the commission and the commission may impose conditions or prescribe terms concerning the new construction that are just and reasonable.

**Right of Eminent Domain.**
Electric light and electric power lines and sites for electric light and power plants are deemed public uses in Utah for which the right of eminent domain may be exercised. See Utah Code Ann. § 78-34-1(8). Before property can be taken, a utility must demonstrate the following four elements:

a. that the use to which it is to be applied is a use authorized by law;
b. that the taking is necessary to such use;
c. that construction and use will commence within a reasonable time as determined by the court;
d. if already appropriated to some public use, that the public use to which it is to be applied is a more necessary public use.

Purpose and necessity of a project is typically a matter of judicial scrutiny. Under Utah case law, a court will not preclude a condemnation action based on a landowner's opinion that a better or different route is available. However, in the planning phases of a route, a utility should consider a rarely used statute that provides that the project must be "located in a manner which will be most compatible with the greatest public good and the least private injury."

**Electrical Facility Review Board Act.**
Pursuant to Utah law, local governments are precluded from imposing certain non-standard requirements without paying the incremental cost difference. A local government may require or condition the construction of a facility (defined as a transmission line in excess of 34,000 volts or a substation) if:

a. the requirements or conditions do not impair that ability of the public utility to provide safe, reliable and adequate service to its customers; and
b. the local government pays for the actual excess cost (costs exceeding standard costs) resulting from the requirements or conditions.

The Electrical Facility Review Board or the commission may provide exceptions to this requirement and require the utility to pay the differential cost. The board is essentially an appellate review for mediating cost differentials and reasonability of requirements and conditions. It is important to note the members of the board have never been appointed and the provisions of this statute have not been used except during permitting hearings to remind local governments that they cannot impose requirements above standard construction without paying the differential costs.

**State Agency Contacts**

Public Service Commission of Utah (certificate of convenience and necessity)
Utah Department of Commerce, Division of Public Utilities
Utah Department of Environmental Quality
- Division of Air Quality
- Division of Solid & Hazardous Waste

Division of Water Quality
Utah Department of Natural Resources
Utah Energy Office
Division of Wildlife Resources (state land issues)
State Parks and Recreation (state land issues)
School and Institutional Trust Lands Administration Surface Management (school land issues)
Labor Commission, Occupational Safety & Health Division
County and Local Governments

**Websites:**
http://www.psc.utah.gov/
http://www.publicutilities.utah.gov/EL003%20Elect%20Siting.html
http://www.commerce.state.ut.us/
http://www.eq.state.ut.us/
http://www.nr.utah.gov/
http://www.utahtrustlands.com/
http://www.uosh.utah.gov/

**Regulatory Citations and Links if applicable:**

Utah Code 54-4-25 and Utah Code 11-13-304 Commission's authority over Certificates of Convenience and Necessity.

Utah Code 54-8c for Public Utility High Voltage Overhead Lines notification and communications requirements

Utah Code 54-7-24 and Utah Code 54-7-25 provide Commission authority to order injunctions or penalties for any public utility violations of compliance with Title 54 or any rule promulgated there under.

Utah Code 78-34-1 (8) for persons exercising eminent domain.

Utah Code 54-14 for the Electrical Facility Review Board Act.

http://www.le.state.ut.us/~code/TITLE54/htm/54_04026.htm

http://www.le.state.ut.us/~code/TITLE11/htm/11_09033.htm

***WYOMING***

The siting of electric transmission lines in Wyoming is not centralized in one governmental entity.

**Utility Regulation**

The Wyoming Public Service Commission has jurisdiction over transmission lines being built by public utilities, exercised through a certification process. See W.S. § 37-2-205. Under this statute, where a certificate is requested for a line of 230 KV or greater, the Commission must publish notice and give all affected landowners actual notice of hearing by registered mail. Commission certificates for such lines must be conditioned "so that no construction of the line is authorized until all right-of-way for the line has been acquired." By rule, the Commission may require a certificate of public convenience and necessity for public utilities' transmission lines designed to operate at 69 KV and above and which are longer than three miles, unless it is construction necessary in the ordinary course of business.

**Right-of-Way/Ways of Necessity**
Electric transmission right of way may be acquired by cities, towns, utilities and others using Wyoming's eminent domain laws. See W.S. §§ 1-26-801 through -817. Beyond this, "any person, association, company or corporation authorized to do business in this state may appropriate by condemnation a way of necessity over, across or on so much of the lands or real property of others as necessary for the location, construction, maintenance and use of . . . electric power transmission lines . . . ." W.S. § 1-26-815 A condemnation proceeding regarding a facility for which a certificate of public necessity and convenience is required cannot go forward until the certificate has been issued. W.S. § 1-26-817. Condemnation actions are brought in Wyoming's District Courts. See Title 1, Chapter 26, Articles 5-8, the Wyoming Eminent Domain Act.

**State Environmental and Siting**
A storm water permit from the Wyoming Department of Environmental Quality would be needed during construction if the surface disturbance exceeds 1 contiguous acre. Lines not exceeding 500 KV are exempt from the Wyoming Industrial Siting Act. See, W.S. § 35-12-119. Certain information must still be filed regarding such exempt activities. See W.S. § 35-12-109(a)(iii), (iv), (v) and (viii). Persons wishing to construct lines crossing or running along roads and highways in Wyoming, including interstates, should first be discussed with the Wyoming Department of Transportation, Utilities Section.

**Counties**
County requirements vary. Persons wishing to construct transmission lines should contact the County Planners in the affected counties (or the County Attorney in the absence of a Planner) to discuss the necessary compliance. Compliance with county utility right-of-way regulations, subdivision regulations and land use plans (concerning zoned county areas) are among the subjects to discuss. Some counties will have additional informational requirements.

**B. Increased Use of Existing Transmission System**
Making the most efficient use of existing transmission infrastructure is a prerequisite for persuading regulators, political leaders and the public, new transmission construction is truly needed. Another concern, raised by wind power representatives at the first RMATS Stakeholder Meeting, was that since many generation projects, and particularly wind projects, can be developed, permitted and built in less than two years, the study time frame of 2008 to 2013 (inherited from SSG-WI) was too distant. In response, RMATS established a Regulatory and Operational Issues Work Group (ROIWG) to explore opportunities to make more efficient use of existing transmission assets without new transmission construction.

In the RMATS region (as in many others), there is no firm Available Transfer Capacity (ATC) available on many transmission paths, even while some paths may be congested for less than 20-50 hours per year. Further, this minimal physical congestion often is during times of low wind output. There may be physical capacity on some paths in the current system to move significant amounts of wind energy, but no access to it under Order 888 tariffs. Wind projects cannot be financed using short-term, non-firm point-to-point service, (the only current alternative to firm service) because non-firm transmission service has no curtailment priority.

The ABB Market Simulation used in the RMATS economic study does not consider regulatory or contractual constraints or operating practices, and therefore does not address tariff limitations. By broadening the scope of the RMATS study beyond economic modeling, RMATS has considered other alternatives to transmission investment. The ROIWG developed a Work Plan to study the

existing operational characteristics of several representative transmission paths important to wind developers, and address whether certain tariff or operational changes could result in increased utilization of the paths. (See Appendix F) It was hoped that this effort could determine whether such tariff and operational changes could enable substantial MW of new resources to connect to the existing transmission system in the near future and over the 4-9 year period before physical transmission upgrades could be permitted and built. These changes would, hopefully, stand on their own merits and thus complement the transmission expansions contained in Recommendations 1 and 2.

The ROIWG conducted its work through numerous conference calls and two meetings in Denver and Portland. A synopsis of the results of the Work Group to date follows:

**ROIWG Case Study Results**

The ROIWG began by reviewing a study of three constrained transmission paths in the West. This study was performed by Peak Power Engineering under a US DOE contract administered by NREL. The purpose of the study was to analyze recent historical power flow data to determine the amount of unused transmission capacity that may be available to new generation resources. The study used geographically relevant wind speed and wind farm output data to correlate wind power availability with transmission capacity. The transmission paths analyzed were the Wyoming to Colorado Front Range (TOT3), Southwestern Wyoming to Utah Wasatch Front (West of Naughton), and the Montana Northwestern Energy to Bonneville Power Administration (Montana-Northwest).

The analyses are general in nature and do not imply that specific generation projects are viable. An OASIS interconnection request and a system impact study are necessary for any new transmission interconnection.

***TOT3***

The TOT3 case study utilized hourly data from the WECC EHV database of the overall path rating, power flow, and schedule for 2001 through 2003. Several factors affecting the available transfer capacity were identified by workgroup participants at the ROIWG meeting in Denver. Issues such as the division of ownership, unscheduled power flow (loop flow), and reserve margins decrease the amount of ATC that is available to a generator.
The study analyzed two cases to determine the available capacity:

*Case 1*

The physically available or Unused Transfer Capacity (UTC) was calculated to identify the total capacity based solely on the historical data.

*Case 2*

The total capacity available for use on an hourly basis was approximated as the hourly ATC, or hATC. This was accomplished by multiplying the UTC by a 60% uncertainty factor. The hATC approximates the overall capacity of the path that may be available to additional generation resources under the proposed conditional firm tariff.

The UTC and the hATC were used in their respective cases to evaluate curtailment likelihood of each of the generation resources. Table 5-1 compares the average curtailment of the three years studied for both cases. **Error! Reference source not found.**Table 5-2 makes the same comparison as Table 5-1 for a 500 MW wind farm.

*Table 5- 1: Average Curtailment Based on Hourly ATC, in Percent of 100MW Wind Farm Total Output*

| | 100 MW Wind Farm | | | | 100 MW Constant Output | | | |
|---|---|---|---|---|---|---|---|---|
| | UTC Curtailed Wind | UTC Non-curtailed Wind | hATC Curtailed Wind | hATC Non-curtailed Wind | UTC Curtailed Constant Output | UTC Non-curtailed Constant Output | hATC Curtailed Constant Output | hATC Non-curtailed Constant Output |
| **Winter** | 0.02% | 99.98% | 0.07% | 99.93% | 0.02% | 99.98% | 0.04% | 99.96% |
| **Spring** | 0.14% | 99.86% | 0.56% | 99.44% | 0.11% | 99.89% | 0.38% | 99.62% |
| **Summer** | 2.42% | 97.58% | 2.87% | 97.13% | 2.76% | 97.24% | 3.63% | 96.37% |
| **Year** | 0.76% | 99.24% | 0.99% | 99.01% | 1.18% | 98.82% | 1.60% | 1.60% |

Note: 100% of wind farm output is an average of 372,593 MWh per year.

*Table 5- 2: Average Curtailment Based on Hourly ATC, in Percent of 500 MW Wind Farm Total Output*

| | 500 MW Wind Farm | | | | 500 MW Constant Output | | | |
|---|---|---|---|---|---|---|---|---|
| | UTC Curtailed Wind | UTC Non-curtailed Wind | hATC Curtailed Wind | hATC Non-curtailed Wind | UTC Curtailed Constant Output | UTC Non-curtailed Constant Output | hATC Curtailed Constant Output | hATC Non-curtailed Constant Output |
| **Winter** | 3.05% | 96.95% | 22.23% | 77.77% | 3.99% | 96.01% | 30.03% | 69.97% |
| **Spring** | 4.42% | 95.58% | 16.04% | 83.96% | 5.89% | 94.11% | 25.26% | 74.74% |
| **Summer** | 11.83% | 88.17% | 31.95% | 68.05% | 15.75% | 84.25% | 43.59% | 56.41% |
| **Year** | 6.25% | 93.75% | 24.89% | 75.11% | 9.24% | 90.76% | 34.92% | 65.08% |

Note: 100% of wind farm output is an average of 1,862,967 MWh per year.

Table 5-1 and Table 5-2 show that curtailment due to insufficient capacity is most likely to occur during the summer operating season. The tables also illustrate the effect of the two cases in the amount of curtailment incurred. Most notable in Table 2, the uncertainty factor increases the likelihood of curtailment for the year from 6.25% to 24.89% for a 500 MW wind farm.

The study also found that on a yearly and seasonal basis, a wind farm is less likely to be curtailed due to transmission constraints than a constant-output generator of the same nominal size. This is due to the lower plant factor (30-40%) for wind which results in a lower probability of coinciding with transmission constraints that require curtailments. The wind farm also is curtailed less as a percent of total capacity output versus traditional generator resources.

The path is owned by four entities, each of which can schedule up to its allocation of the real-time Total Transfer Capability (TTC). Each entity's allocation is proportional to its percent ownership of TOT3. One entity who owns TOT2 transmission is a parent company made up of three separate companies. Curtailment of schedules can occur if an entity over-schedules its portion of the TTC, even if other entities have not reached their schedule limits. In the case of the parent company, each separate constituent company may use all of the ATC available to the parent company as long as the

other constituent companies do not use their share of the ATC. The data used for the study does not show these interactions between entities.
Having studied TOT3 as a single path for the purpose of simplifying the analysis, the ROIWG recognizes that it is not practical to assume that all of the unused capacity can be made available as ATC. The complex ownership and multiple separate lines in the TOT3 path make it difficult to determine potential ATC available, without detailed power flow studies which are based on actual points of receipt and delivery. The study was not able to take into account these issues that would limit the ATC available on TOT3. The purpose of the analysis was to demonstrate that there may be the potential, as identified by future detailed studies, for additional utilization of the system if new tariff products are developed and implemented as described below.

***West of Naughton***

The West of Naughton case study was conducted using actual power flow data for the path obtained from PacifiCorp. Due to recent system changes, load growth, and the development of 144 MW of new wind power brought on line in December 2003, the data set used for West of Naughton is no longer relevant to the path. Furthermore, West of Naughton is operated as an "internal" path, and is therefore not specifically scheduled. New data that is indicative of the system changes at West of Naughton is required to complete a meaningful study of this path.

***Montana-Northwest***

Several key issues were identified in the Montana-Northwest case study at the ROIWG meeting in Portland. The data that is stored in the WECC EHV database for the Montana-Northwest path is missing significant portions of real-time data such as hourly schedule and path rating. This is due to data recorder errors and problems with the reporting process.

The incompleteness of the data used for the path, and mismatched time periods between the transmission data and the wind data sets limit the conclusions that can be drawn from the preliminary results. The study method was similar to that used for TOT3 in that it evaluated the overall capacity of the Montana-Northwest path. The preliminary results suggest that a 500 MW wind farm has a curtailment likelihood of 1.25% of its yearly output, whereas a constant-output plant of 500 MW has a curtailment likelihood of 3.53% of its yearly output. It is important to note that the curtailment values may be significantly overstated due to the lack of real-time transmission data. Additionally, the effect of reduced transmission capacity for wind farm locations east of Garrison, MT or the Amps line was not readily quantifiable.

Additional study work for the Montana-Northwest path will require more complete scheduling data or ATC data. More complete and reliable data recording is also necessary to conduct an accurate analysis of the historical loading and available capacity. It may be necessary to acquire path data east of Garrison in order to accurately evaluate the capacity for wind resources in central and eastern Montana.

**Case Study Conclusions**

The results of the case studies illustrate several key issues regarding the assessment of available capacity of the paths:

a. More efficient use of TOT3 may be possible by reviewing the operating practices that divide ATC among owners of the path and performing more detailed studies on path utilization.

b. Improved data collection and completeness of the WECC EHV database will aid in the accuracy of future studies.
c. The addition of posted ATC values to the EHV database may be helpful in comparing unscheduled capacity to posted ATC. This may lead to improved calculation methods for ATC, and ultimately to more efficient use of the transmission system.

The ROIWG Case Study provided sufficient information about the potential for increased utilization of the existing system to prompt the Work Group to pursue the development of new transmission tariff products as the principal output of the group's effort.

For additional information related to this Case Study, see Appendix H.

**ROIWG Tariff Development Results**

In the ROIWG meetings in Denver and Portland, the Work Group discussed numerous innovative tariff considerations which could pave the way to potential additional utilization of the existing transmission system. Tariff innovation ideas focused on a possible "conditional firm" product which would offer firm service except for certain defined periods, and a long-term "priority non-firm" product that would offer a high priority non-firm service on a long-term contract basis. The ROIWG has informally developed generic draft wording for OATT tariff modifications to include these tariff innovations.

Many generators and utilities feel that they can work with a transmission product with a limited curtailment risk during a few months of the year. Intermittent generators like wind, do not use the full transmission capacity in their contracts, and will be less impacted by a small curtailment risk, which may not coincide with their generation patterns. Generators and utilities are not comfortable signing twenty-year contracts for new resources with the risks inherent in transmitting that power strictly via non-firm transmission service (available for only one year). Since new transmission lines to serve generators cannot be developed in the near term future, innovative transmission tariff products that make more efficient use of the transmission system, and particularly constrained paths, will allow for new generation alternatives sooner rather than later. A "conditional-firm" transmission tariff product can provide a bridge until more transmission can be added to the system. It can also provide additional revenue for existing transmission owners. A long-term priority non-firm tariff product could also be useful under certain circumstances.

<u>Conditional-Firm Service Tariff Product</u>

The conditional-firm transmission product would be for firm service during a defined period of the year and conditional-firm service for the balance of the year. Conditional-firm would be curtailed prior to firm service, but after all non-firm service. This priority of curtailment combined with a clear understanding of the curtailment risk during the conditional months will give generators and utilities more confidence in their ability to move power to loads.

The Conditional-Firm Service would have the following characteristics:

- Conditional-firm service would be offered to customers when ATC to meet a long term firm request is not available for the full amount of the request for twelve months of the year.
- Conditional-firm service would be offered for the same duration as long-term firm.

- Conditional-firm service would be a combination of firm service for a set number of months of the year with service curtailment for the remaining of the year.
- This curtailment priority would mean that the transmission service would be curtailed after non-firm service but prior to firm service and the service would be subject to curtailment only as necessary to maintain system reliability and not for economic or other non-reliability reasons.
- Customers purchasing conditional-firm service would be given detailed information about curtailment risk, i.e. the hours of likely curtailment, during conditional service months of the year in advance of their commitment.
- Customers purchasing conditional-firm service would have a right to retain their original queue status.
- This service would be appropriately priced relative to long-term firm service, reflecting its higher potential for curtailment.

The ROIWG has been working on draft generic OATT tariff language to further define the conditional-firm tariff product. This draft is a work-in-progress that will likely be subject to further analysis and modification by interested parties.

Priority Non-Firm Service Tariff Product

Point to point transmission service is defined in OATT-compliant tariffs as either firm or non-firm. NERC and tagging processes have defined seven levels of firmness for point-to-point service: 1) redirect from secondary points on the system, 2) hourly non-firm, 3) daily non-firm, 4) weekly non-firm, 5) monthly non-firm, 6) network service from secondary non-Network resources, and 7) firm. These categories allow transmission operators to curtail by level of firmness. The ROIWG has pursued the development of a non-firm transmission tariff product offering a new "category 5.5" service, available long term, in which the customer would agree to be curtailed when the operations were constrained.

The requirements associated with network service (priority 6) and that non-firm service is not available for periods longer than one year is an impediment for new intermittent generators to procure financing. Yet there is transmission capacity available on most paths in many hours of the year. A priority Non-Firm transmission product could enable generators to use this capacity. Given the current point-to-point tariff and the associated priority levels that range from 1-7, it appears that a level 5.5 priority would be a logical candidate for tariff modification. This product would have a lower priority than firm service, and would therefore be subject to curtailment before any firm curtailment. A level 5.5 priority would also be curtailed prior to curtailment of a secondary network resource, but would receive priority over all other non-firm service. Because Non-Firm Point-To-Point Transmission Service applies to non-network loads and resources, a long-term product would be useful for either merchant wind plants or for entities that do not have a network agreement in place.

The Long-Term Non-Firm Point-To-Point Transmission Service Product would have the following characteristics:

- Long-Term Non-Firm service would be offered to customers when there is sufficient capacity available for portions of the year.
- Long-Term Non-Firm service would be offered for a period of up to ten years.

- The curtailment priority would mean that the transmission service would be curtailed after non-firm priorities 1-5 but prior to secondary service priority 6 and firm service priority 7.
- Customers purchasing long-term non-firm service would be given detailed information about curtailment risk in advance of their commitment.
- Customers purchasing long-term non-firm service would have a right to retain their original queue status.
- Pricing for this service would be based on its proportionate use of the system.

The ROIWG has been working on draft generic OATT tariff language to further define a priority non-firm service tariff product. This draft is a work-in-progress that will be subject to further analysis and modification by interested parties.

Conclusion

The ROIWG will continue to work on draft generic OATT tariff language to further define these tariff products in RMATS Phase II with the goal of persuading target utilities to file these products with the FERC.

### C. Emerging Transmission Technologies

The identification of transmission solutions to reduce VOM costs in 2013 focused on the addition of new 230 KV, 345 KV, and 500 KV transmission lines, the addition of series compensation, and installation of phase shifters. New technologies are being developed to increase transfer capacity on existing lines within existing corridors, including advanced composite conductors, more compact transmission line configurations, Flexible AC Transmission Systems and new sensors and control devices. See Appendix C.3.b for a description of new transmission technologies.

Several of these technologies have the potential of minimizing environmental impacts and local opposition to transmission expansion projects. Project sponsors should carefully examine the application of such technologies in their transmission plans.

# Chapter 6 - Summary of Recommendations and Next Steps

## A. Transmission Recommendations

Phase I of the RMATS process yielded two sets of recommendations for projects which are capable of producing increased transmission capacity and significant economic benefits.

**Recommendation 1:** Inside the RMATS footprint, three discrete projects are recommended: the Montana System Upgrade, the Bridger Expansion Project, and the Wyoming to Colorado Project. As discussed in Chapter 3, an economic comparison of Recommendation 1 with the two Reference Cases indicates these three transmission expansion projects are cost justified and capable of producing annual net savings of $61 million to $531 million per year. While each project is discrete, the three projects together provide the greatest benefit to the region. This outcome illustrates the substantial value of regional cooperation to develop a solution which fairly allocates and recovers the costs and benefits of these projects.

**Recommendation 2:** This Recommendation, also discussed in Chapter 3, builds on Recommendation 1 by identifying optional transmission projects to export an additional 3,900 MW of electricity from the RMATS region to relatively higher-cost markets in the West, including California. These projects bring the benefits of fuel diversity and lower generation costs while promoting competitive market development.

Using reasonable assumptions, Recommendation 2 shows significant consumer benefits for the Western Interconnection. An economic comparison of Recommendation 2 with the two Reference Cases indicates that these transmission expansion projects are cost justified and capable of producing annual net savings of $516 million to $986 million per year.

RMATS recommends that further work on Recommendation 2 should be coordinated with California transmission planners and SSG-WI's west-wide planning process. Planning for cost allocation and cost recovery for Recommendation 2 should be on a basis broader than the RMATS footprint in recognition of the distribution of potential benefits.

## B. Phase II and Beyond: Recommendations for Further Action in Project Development

Much work remains. There are important financial, regulatory, legal and practical issues that must be addressed to facilitate development of the RMATS recommendations. Chapter 4 provides a detailed discussion on cost allocation and cost recovery issues, with specific recommendations for proceeding to address these issues. Other key issues that need to be addressed in Phase II are discussed in Chapter 5.

As an initial step to begin Phase II, RMATS recommends that for each discrete transmission expansion project, the Governors of the states involved with each project convene a meeting with their public service commissioners and the senior executives of the entities most likely to benefit from the expansion project. These meetings would include a review of the RMATS findings and begin discussing further steps in project development. If successful, these meetings will result in commitments from parties to sponsor further work on each recommendation, including technical studies and discussion on regulatory treatment and financing.

RMATS also recommends several institutional improvements. To improve the process of evaluating and financing transmission expansion and operate the existing transmission system more efficiently, RMATS recommends that:

- Multi-state transmission expansion pricing principles be developed;
- The Wyoming Infrastructure Authority be engaged in transmission expansion financing discussions;
- Efforts begun in the RMATS process to link load-serving entity resource plans to regional transmission plans be expanded;
- The evaluation of transmission expansion to facilitate power exports from the RMATS region be integrated with regional planning in other parts of the Western Interconnection;
- Governors and regulators consider the formulation of a Regional Transmission Organization (RTO) with features appropriate to the region, including independence and cost-effectiveness; and,
- That transmission owners develop conditional firm or priority non-firm transmission products that quantify curtailment risks and curtailment priority in order to better utilize physical transfer capacity on existing lines.

Further, the following specific actions are recommended:

1. To address cost allocation and recovery uncertainties, RMATS recommends that the state public utility commissions and energy agencies in the five states in the RMATS footprint deliver a report to their Governors in six months discussing multi-state transmission expansion cost recovery and pricing principles.

2. RMATS recommends that the regulatory commissions in Colorado, Idaho, Montana, Utah and Wyoming enter into a memorandum of agreement adopting pricing principles, and jointly file the MOA with FERC, requesting its endorsement. These principles would then apply to any applications for transmission cost recovery received by regulatory commissions within the RMATS region, providing a degree of certainty and consistency in regulatory treatment.

3. RMATS recommends that its transmission recommendations be considered in the development of resource plans of load-serving entities in the Rocky Mountain region and regulatory commission reviews of such plans. RMATS also recommends that future regional transmission planning in the Rocky Mountain region reflect the resource plans and acquisition activities of load-serving entities in the region.

4. RMATS recommends that the RMATS Steering Committee, Load Forecasting Work Group, Resource Additions Work Group, Transmission Additions Work Group, and Cost Allocation/Cost Recovery Team be maintained and be available to conduct additional work as conditions warrant. An agreement among states and the electric power industry to maintain and finance a pro-active transmission planning process in the Rocky Mountain region is needed.

5. RMATS recommends that SSG-WI use RMATS export case analyses in the development of an interconnection-wide "realistic" generation scenario that would be studied in late 2004 and early 2005.

### C. Conclusion

Over the past twelve months, the first phase of RMATS reached consensus conclusions recommending specific transmission expansion projects and a number of next steps for Phase II. This successful conclusion of Phase I can be attributed solely to the significant contributions from the participants, including State policy-makers and regulators, utilities, generation and transmission developers, and other interested parties. Phase II will be successful only if this participation continues. Phase II will depend on interested parties stepping forward with commitments to sponsor projects, and forming partnerships which may include public and private entities, regulators and policy-makers.

# APPENDIX A-5-F

# APPENDIX A-5-F

## Glossary

**ABB Market Simulator model:** The ABB (Asea Brown Boveri) Market Simulator computer production costing model was developed to predict the economic and physical performance of large power networks on an hourly basis. The application was designed to produce estimated market clearing prices that vary by location (bus or node), lowest-cost generating resource dispatch, and to identify transmission congestion. It illustrates system-wide effects of proposed transmission expansion and allows exploration of sensitivities.

**ATC or Available Transfer Capability:** A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above the capacity already committed to other uses.

**BLM:** The Bureau of Land Management is an agency within the U.S. Department of the Interior which administers federal public lands located primarily in 12 western states, including the RMATS states. The BLM can, based on a public interest standard, issue right-of-way grants for electrical generation, transmission and distribution systems under Title V of the Federal Land Policy and Management Act of 1976 (43 U.S.C. §§ 1761-1771). Visit the BLM at http://www.blm.gov/nhp/index.htm

**"Bubbles":** For purposes of the RMATS study, areas in the RMATS regions were broken down into "bubbles" which summarize load and generation data for a particular geographic area. Building on similar bubbles used by SSG-WI, RMATS provides significant increases in granularity

**Bus price:** The price of a unit of electricity at the busbar of the plant at which it is produced.

**CACRT:** The Cost Assignment and Cost Recovery Team in RMATS. See a basic description of their work in the Report Appendices.

**CCCT or Combined-Cycle Combustion Turbine:** A generation unit which combines a natural gas-fueled combustion turbine with a steam turbine to produce electricity.

**CFR** The Code of Federal Regulations. It is the standard compilation of all federal agency regulations. References can be to either individual sections or Parts containing several sections on a single topic. Their numbering (e.g., 16 CFR) follows the numbering of titles in the United States Code.

**DSM:** Demand side management. Programs which seek to lower the demand for electricity, including, e.g., programs to shift loads off peak and to increase energy efficiency.

**Enlibra Principles:** A group of common principles developed by the WGA underlying the most promising approaches and successful solutions to environmental problems. Enlibra seeks greater participation and collaboration in decision-making, a focus on outcomes rather than just programs, and recognition of the need for a variety of tools beyond regulation that will improve environmental and natural resource management. Like RMATS, Enlibra recognizes that successful policy implementation is best accomplished through balanced, open and inclusive processes at the appropriate geographic level.

Enlibra is discussed at http://www.westgov.org/wga/initiatives/enlibra/default.htm
See WGA's policy resolution at http://www.westgov.org/wga/policy/02/enlibra_07.pdf

**IPP:** The Intermountain Power Project includes a two-unit, coal-fired, steam electric generating station, with a net capacity of 1730 MW located in Delta, Utah. Learn more about IPP on the web at: http://www.ipautah.com/aboutus.htm

**IRP:** Integrated Resource Plan

**LFWG:** The Load Forecasting Work Croup in RMATS. See a basic description of their work in the Report Appendices.

**Locational Marginal Pricing or LMP:** The locational marginal price expresses the cost of delivering the next MW (or other increment) of power to a particular location, or the savings from reducing load by 1 MW (or other increment) at that location (sometimes called a shadow price). LMP is used by RMATS for the sake of modeling convenience and uniformity in assessing the the ABB Market Simulator Model results by allowing the evaluation of pricing on a comparable basis throughout the RMATS region. For modeling purposes, it only expresses uniformly determined prices akin to those which might be found in a fully competitive market. The application of LMP in practice has generated some controversy (as an

element of standard market design. Our use of LMP should not be considered as a decision of RMATS to advocate the mandatory use of LMP in practice. For an expanded discussion of how to interpret the model outputs see the SSG-WI October 2003 report.

**LSE:** A load serving entity. One which provides electric service to retail customers.

**MMBtu**: One million British Thermal Units. Natural gas prices are often expressed in terms of MMBtus.

**MW:** A megawatt -- one million watts or 1,000 kilowatts.

**Nodal pricing:** Simply expressed as LMP at the node, nodal pricing is a method in which market clearing prices are calculated for a number of locations on the transmission grid (nodes). Each node represents a physical location on the transmission system, and it can include both generators and loads. The price at each node represents the locational value of energy, including the cost of the energy and the cost of delivering it (including losses and congestion). Nodal prices are determined by calculating the incremental cost of serving one additional MW of load at each location subject to system constraints (i.e. transmission limits, contingency analyses, etc.).

**OATT:** Open Access Transmission Tariffs. Developed under FERC Order 888 concerning the encouragement of competition in the wholesale electric transmission market.

**Order 888:** The FERC's Order 888 required all public utilities that own, control or operate interstate transmission facilities [a] to file nondiscriminatory open-access transmission tariffs with certain basic non-price terms and [b] to functionally unbundle wholesale power services from transmission services, which would require public utilities to [a] take wholesale transmission services under the same tariff as their customers; [b] state separate rates for wholesale generation, transmission, and ancillary services; and [c] use the same information network as their customers do to obtain information about the utilities' transmission systems.

*Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ; 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (March 14, 1997), FERC Stats. & Regs. 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC , 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC 61,046 (1998), aff'd in relevant part, remanded in part on other grounds sub nom. *Transmission Access Policy Study Group, et al. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. *New York v. FERC*, 122 S. Ct. 1012 (2002).

**Order 889:** The FERC's Order 889, issued concurrently with Order 888, imposed standards of conduct governing communications between a utility's transmission and wholesale power functions, preventing the utility from giving its power marketing arm preferential access to transmission information. All public utilities that own, control or operate interstate transmission facilities must also create or participate in an electronic information system (OASIS) that provides current and potential transmission customers the same access to transmission information, enabling them to obtain discriminatory open-access non-transmission service.

Open Access Same-Time Information System and Standards of Conduct, Order No. 889, 61 Fed. Reg. 21,737 (April 24 1996), FERC Stats. & Regs. ¶ 31,035 at 31,588-91 (1996), order on reh'g, Order No. 889-A, 62 Fed. Reg. 12,484 (March 4, 1997), FERC Stats. & Regs. ¶ 31,049 (1997).

**RAWG:** The Resource Additions Work Group in RMATS. See a basic description of their work in the Report Appendices.

**RMATS:** The Rocky Mountain Area Transmission Study. It brings together concerned stakeholders from Utah, Wyoming, Montana, Idaho, and Colorado to examine and understand better the electric transmission needs of the 5-state region and to recommend the most necessary and financially viable projects to enhance transmission infrastructure. Visit RMATS at http://psc.state.wy.us/htdocs/subregional/home.htm

**ROIWG:** The Regulatory and Operational Issues Work Group in RMATS, charged with addressing opportunities for more efficient use of the existing transmission system, going beyond economic modeling and dealing with issues of intermittent resources (wind power), tariffs and other pertinent topics.

**RTO or Regional Transmission Organization:** Developed conceptually in orders of the Federal Energy Regulatory Commission as entities which would provide comprehensive management of the nation's electric transmission system, RTOs are intended to increase transmission efficiency, eliminate bottlenecks, facilitate the development of competitive wholesale markets and provide governance in the rational development and use of transmission assets in the future.

**Series Compensation:** A series capacitor installed on a transmission line generates reactive power that balances a portion of the line's transfer reactance. It is intended to improve the functionality of the transmission system, including [a] improved voltage stability of the corridor and [b] optimized power sharing between parallel circuits.

**SSG-WI or Seams Steering Group-Western Interconnection:** SSG-WI serves as a discussion forum for facilitating the creation of a seamless Western electricity market and for proposing resolutions for issues associated with differences in RTO practices and procedures. The member RTOs includes WestConnect, the California ISO and Grid West (formerly RTO WEST). Representatives of RTOs, utilities, consumers, regulators and other groups participate in the SSG-WI process. Visit SSG-WI at
http://www.ssg-wi.com/

**TAWG**: The Transmission Additions Work Group in RMATS. See a basic description of their work in the Report Appendices.

**USC** The United States Code. The official reference to codified federal statutes. A sample citation -- 16 USC § 470 -- denotes "Title 16 of the United States Code, Section 470."

**VOM:** Variable Operating and Maintenance Cost As used in the RMATS study, the ABB Market Simulator dispatches new and existing generation based on the lowest variable operating and maintenance cost of the generating units.

**WAPA:** The Western Area Power Administration. WAPA markets and delivers hydroelectric power and related services within a 15-state region of the central and western United States, including all of the RMATS states except Idaho. It is one of four power marketing administrations (or PMAs) within the United States. Department of Energy which market and transmit electricity from multi-use water projects. WAPA's system carries electricity from 55 hydropower plants operated by the Bureau of Reclamation, U.S. Army Corps of Engineers and the International Boundary and Water Commission. Western accepts requests from electric utilities, firm-power customers, private power developers, and independent power generators to interconnect with its transmission system Visit WAPA at http://www.wapa.gov/

**WECC:** The Western Electricity Coordinating Council is the regional reliability council covering the entire Western Interconnection. It is one of 11 regional reliability councils in North America. WECC focuses on ensuring the reliability of the western grid. It was formed in April 2002, by the merger of Western Systems Coordinating Council, Southwest Regional Transmission Association (SWRTA), and Western Regional Transmission Association (WRTA). Visit WECC at http://www.wecc.biz/main.html

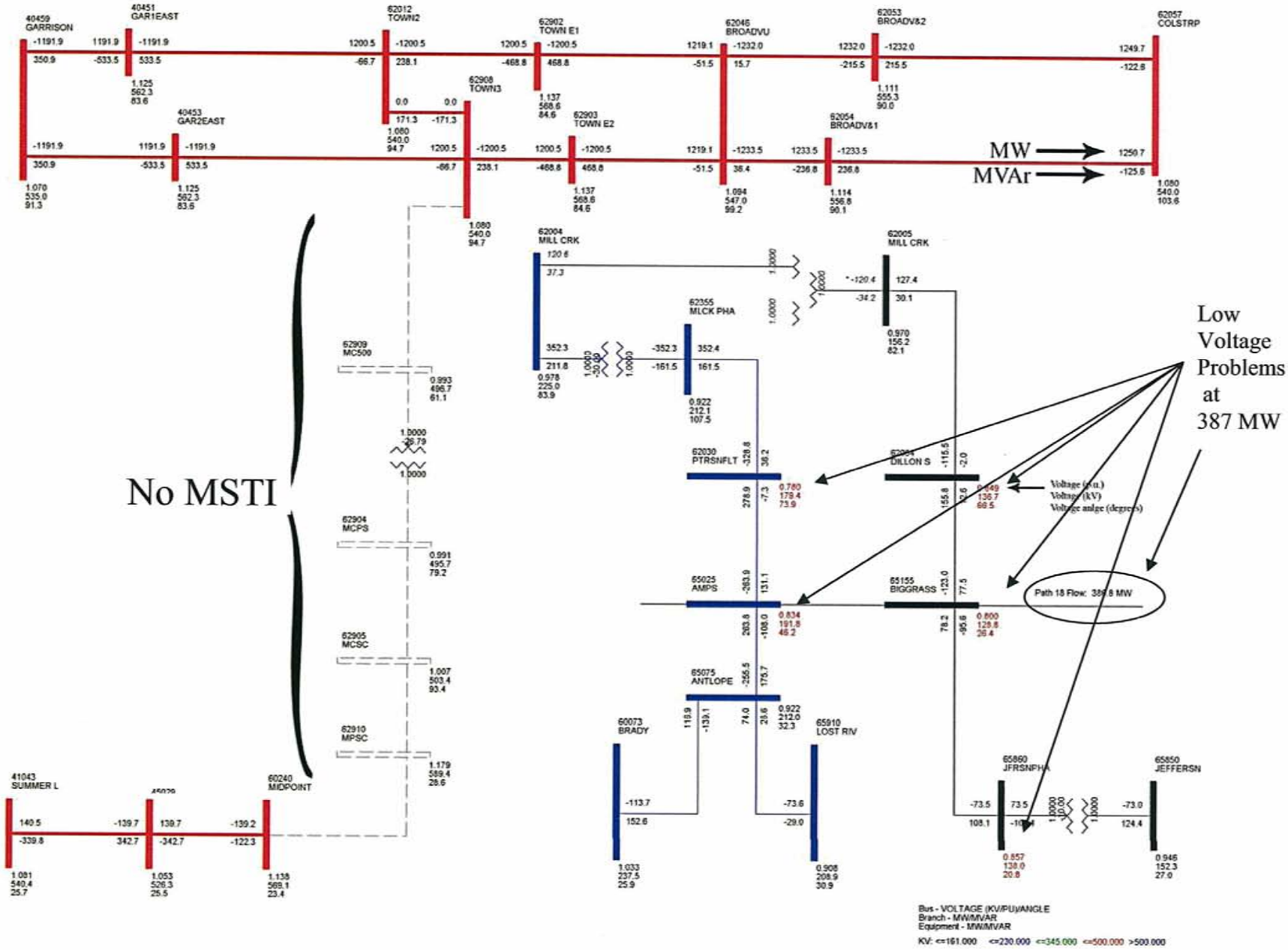
**Western Interconnection:** The Western Interconnection is the electric power transmission system currently existing in all or part of 14 western states, two Canadian Provinces and a portion of northern Mexico. Private and public entities developed the interconnected system organically to serve the needs of their own load bases but did so in consideration of enhancing system reliability and efficiency. It is virtually a self-contained network and is characterized by some stability (e.g., loop flow) and transfer limitations (e.g., path congestion) stemming from its physical makeup and the very long transmission lines which characterize it.

**WGA or Western Governors' Association**: WGA *serves the Governors of 21 states and US-Flag Pacific Islands, including* Alaska, American Samoa, Arizona, California, Colorado, Guam, Hawaii, Idaho, Kansas, Montana, Nebraska, Nevada, New Mexico, North Dakota, Northern Mariana Islands, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming. It works on policy, social and governance issues in the West, serves as a voice for the West in the federal system, and promotes shared development of solutions to regional problems. A center for innovation, WGA develops policy and carries out programs in the areas of natural resources, the environment, human services, economic development, international relations and state governance. Visit WGA at http://www.westgov.org/

# APPENDIX A-5-F

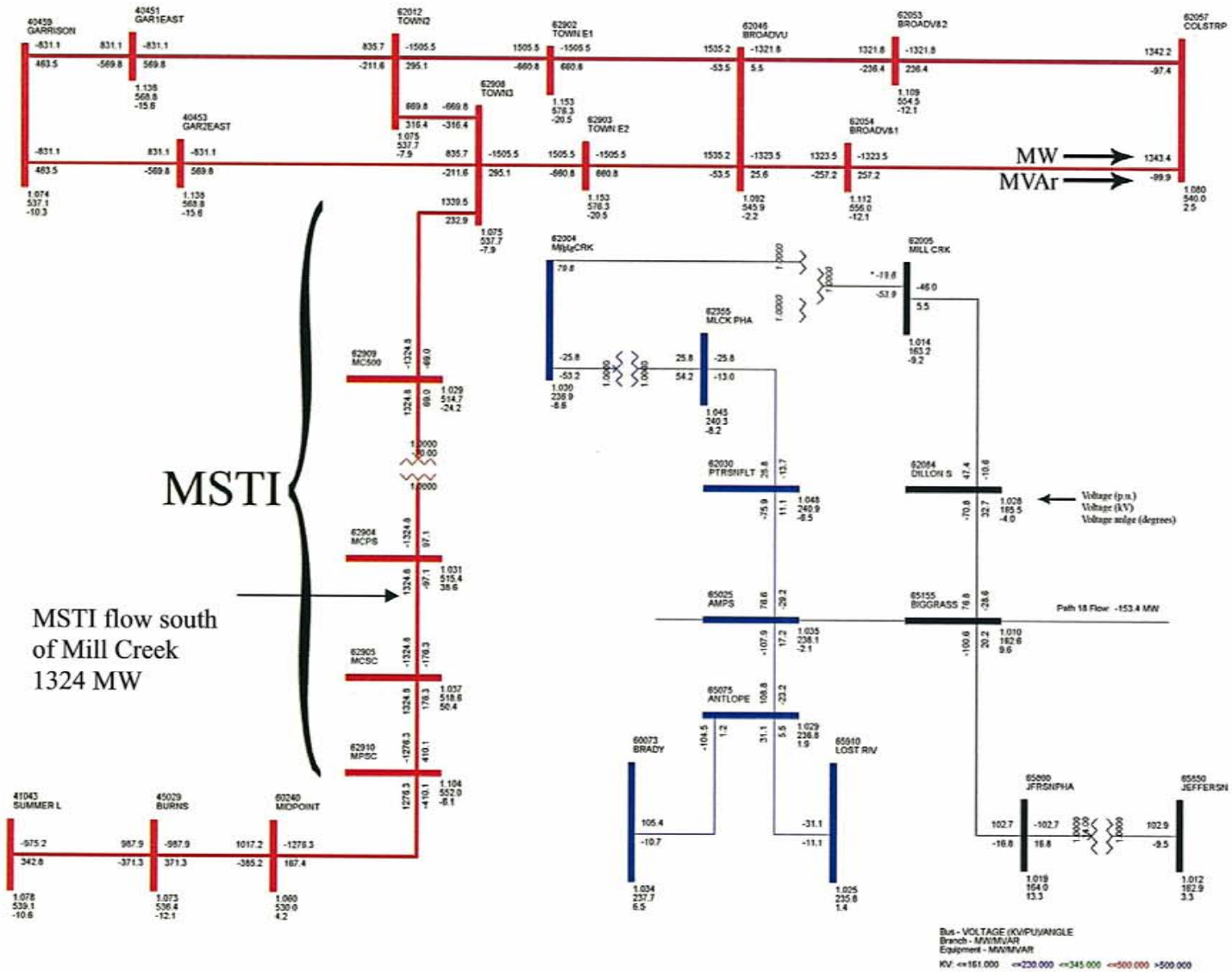
**APPENDIX A-5-G**

# Base Case Illustrating The Problem - 2010
# Path 18 at 387 MW Without MSTI



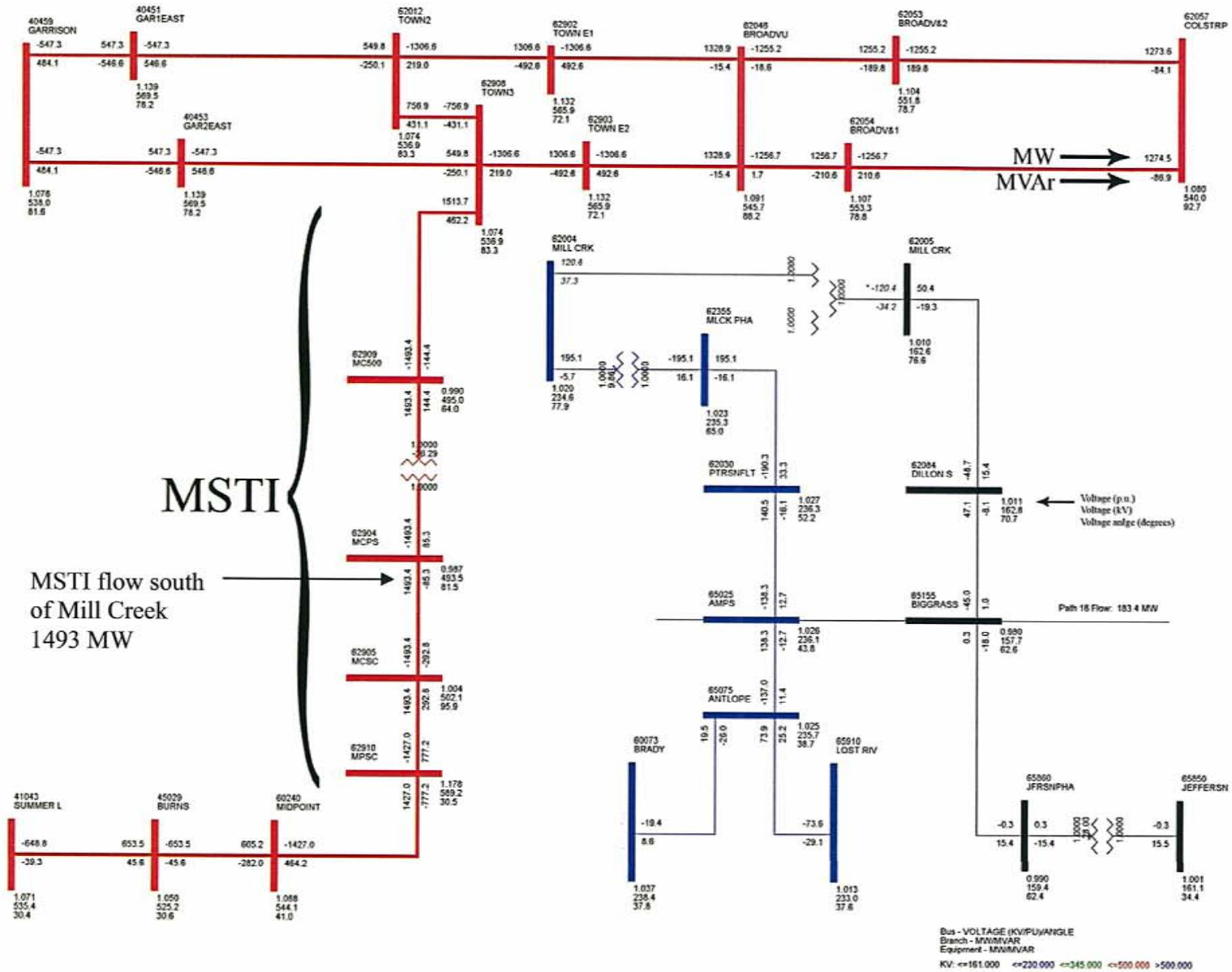
**APPENDIX A-5-H**

# Example of Immediate Effects Of MSTI – 2010



**APPENDIX A-5-I**

# Example Effect Of MSTI Five Years Later – 2015

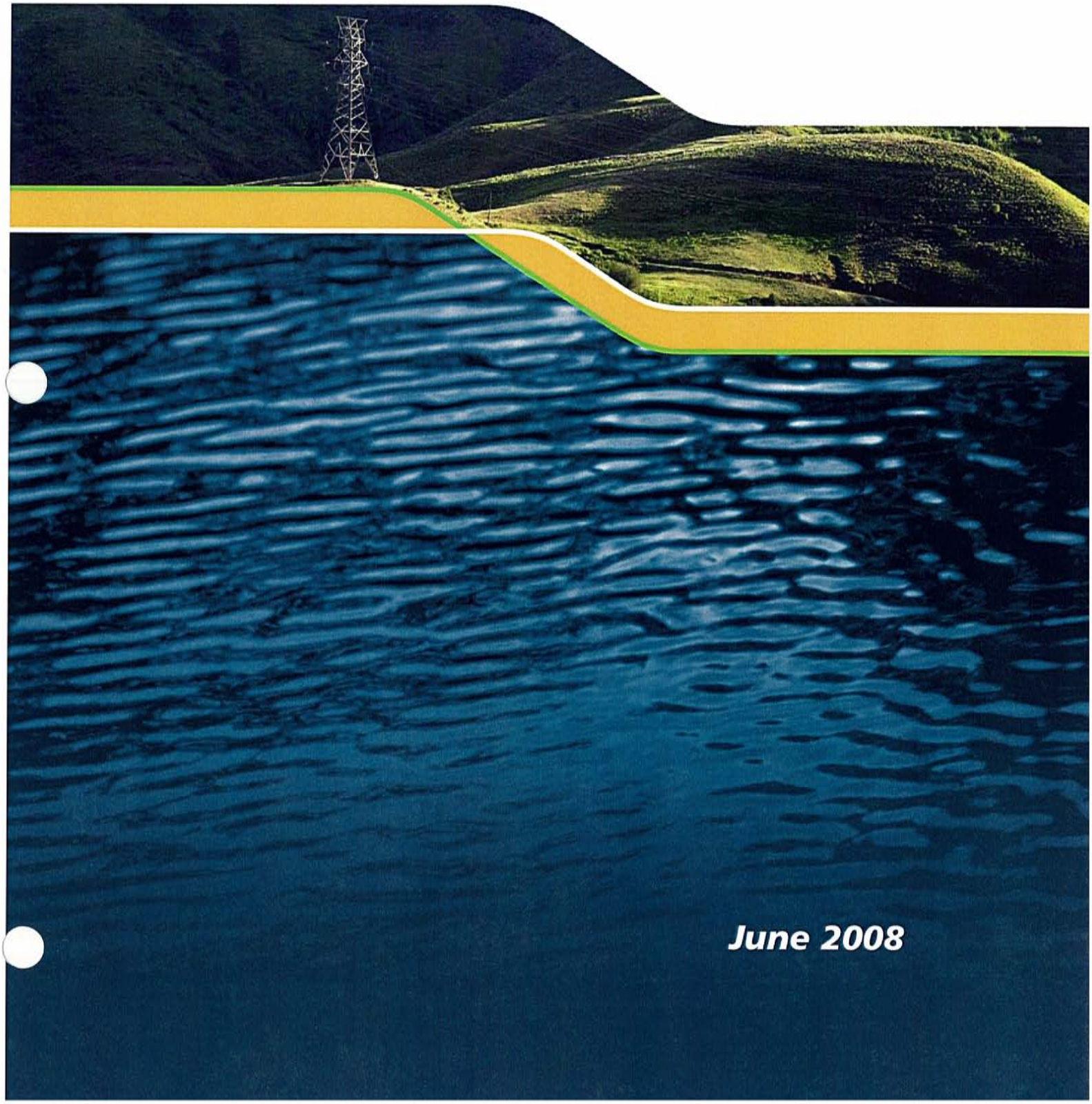


# APPENDIX A-5-J

IDAHO POWER.
An IDACORP Company

# 2008 Integrated Resource Plan UPDATE

**IRPAC DRAFT**
**May 19, 2008**



*June 2008*

# IRPAC DRAFT - May 19, 2008

## *2008 Integrated Resource Plan UPDATE*

IDAHO POWER®
An IDACORP Company

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# GLOSSARY OF TERMS

A/C – Air Conditioning

aMW – Average Megawatt

CCCT – Combined-Cycle Combustion Turbine

CFL – Compact Fluorescent Light

CHP – Combined Heat and Power

$CO_2$ – Carbon Dioxide

CSPP – Cogeneration and Small Power Producers

DSM – Demand-Side Management

EA – Environmental Assessment

EEAG – Energy Efficiency Advisory Group

EIA – Energy Information Administration

FCA – Fixed Cost Adjustment

FERC – Federal Energy Regulatory Commission

FPA – Federal Power Act

HCC – Hells Canyon Complex

IDWR – Idaho Department of Water Resources

IGCC – Integrated Gasification Combined Cycle

INL – Idaho National Laboratory

Idaho PUC – Idaho Public Utilities Commission

IRP – Integrated Resource Plan

IRPAC – Integrated Resource Plan Advisory Council

kV – Kilovolt

kW – Kilowatt

kWh – Kilowatt Hour

MAF – Million Acre Feet

MMBtu – Million British Thermal Units

MSTI – Mountain States Transmission Intertie

MW – Megawatt

MWh – Megawatt Hour

NEPA – National Environmental Policy Act

NTTG – Northern Tier Transmission Group

NWPCC – Northwest Power and Conservation Council

Oregon PUC – Public Utility Commission of Oregon

PCA – Power Cost Adjustment

PM&E – Protection, Mitigation, and Enhancement

PURPA – Public Utility Regulatory Policies Act of 1978

REC – Renewable Energy Credit

RFP – Request for Proposals

RPS – Renewable Portfolio Standard

$SO_2$ – Sulfur Dioxide

WECC – Western Electricity Coordinating Council

WREGIS – Western Renewable Energy Generation Information System

# 1. INTRODUCTION

Idaho Power Company filed the 2006 Integrated Resource Plan (IRP) in the fall of 2006. The Idaho Public Utilities Commission (Idaho PUC) accepted the plan for filing in Order 30281 issued on March 26, 2007. In April 2007, Idaho Power requested a one-year delay in the filing of its next IRP until June 2009 to coordinate the filing with the Avista and PacifiCorp Integrated Resource Plans. The Idaho PUC accepted the one-year IRP filing delay in Order 30317 issued on May 23, 2007.

The Idaho PUC further noted in Order 30317 "Idaho Power also proposes to file an 'IRP update' in June 2008 to highlight the progression in its short-term action plan, changes in its load forecast, existing loads, customer base and purchased power contracts; and any significant deviations from its 2006 IRP." The Idaho PUC required Idaho Power to file the IRP update in June 2008 as part of Order 30317.

The Idaho PUC is not alone in requesting an IRP update. The Public Utility Commission of Oregon (Oregon PUC) specified that utilities file an IRP update within one year of the most recent IRP acknowledgement date as part of Order 07-002 issued in January 2007.

The resource plan update is expected to be an informational filing and the update requirements specified by the Oregon PUC are similar to the Idaho requirements. In Order 07-002, the Oregon PUC requires that utilities "describe what actions the utility has taken to implement the plan; provide an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource

**2008 IRP Update Highlights**

- Idaho Power expects to add 12,500 to 13,000 new customers annually over the next 20 years (Section 3).
- Idaho Power's average annual load is forecast to increase 30 aMW per year over the next 20 years (Section 3).
- Idaho Power's peak-hour demand is forecast to grow 70 MW per year over the next 20 years (Section 3).
- Recent demand-side management (DSM) program performance has exceeded expectations (Section 4).
- In September 2007, Idaho Power decided to no longer pursue the development of a conventional coal resource in 2013 (Section 5).
- In October 2007, U.S. Geothermal begins delivering energy to Idaho Power from the Raft River Geothermal Project (Section 5).
- In November 2007, Horizon Wind Energy begins delivering energy to Idaho Power from the Elkhorn Valley Wind Project (Section 5).
- In April 2008, Idaho Power issued the 2012 Baseload Resource RFP (Section 5).
- As a member of the Northern Tier Transmission Group (NTTG), Idaho Power is in the initial phase of developing two "fast track" projects that were identified in the 2006 IRP (Section 6).

acquisitions, resource costs, and transmission availability; and justify any deviations from the acknowledged action plan."

Integrated resource planning is a dynamic process and during the time between resource plan filings, the public and regulatory oversight of the activities identified in the IRP allows for discussion and adjustment of the IRP as warranted. Idaho Power continues to analyze and evaluate the resource plan and make periodic adjustments and corrections to reflect changes in technology, economic conditions, anticipated resource development, and regulatory requirements.

This update outlines the changes to the 2006 IRP that have occurred since the plan was filed in the fall of 2006. Idaho Power intends to file a complete IRP in June 2009. The 2008 IRP Update is a summary of the resource plan changes that have occurred since the 2006 IRP and is limited in scope and analysis.

# 2. Idaho Power Company Today

## Regulatory Issues

Idaho Power operates in both Idaho and Oregon and the company's operations are regulated by the Idaho PUC and the Oregon PUC. Since filing the 2006 IRP, Idaho Power has been involved in a number of significant regulatory proceedings in each state jurisdiction.

### *Idaho Proceedings*

- **IPC-E-07-03**
  Increase Wind Power Rate Eligibility Cap & Eliminate 90/110 Performance Band (wind integration issue, also includes IPC-E-05-22 Temporary Suspend PURPA Obligation Re Wind Power), Order No. 30488

- **IPC-E-07-15**
  Modify Methodology of Determining Fuel Costs to Establish Published Rates

- **IPC-E-07-18**
  Idaho Power – $SO_2$ Allowances Revenue Allocation, Order No. 30529

### *Oregon Proceedings*

- **UM 1056**
  Investigation into whether the requirements for least-cost planning, first established in Order 89-507, should be revised, Order No. 07-002

- **SB838C**
  Oregon Renewable Energy Act

- **UM 1302**
  Investigation into the Treatment of $CO_2$ Risk in the IRP Process

- **UM 1066**
  Investigation into regulatory policies affecting new resource development

### *Idaho Energy Plan*

In 2006, the Idaho Legislature directed an Interim Committee on Energy, Environment and Technology (the Committee) to develop a state energy plan that provides for the state's power generation needs and protects the health and safety of the citizens of Idaho. In January 2007, the Committee completed the Idaho Energy Plan and concluded that all of Idaho's energy systems have performed very well with electric and natural gas prices that remain some of the lowest in the country.

The Committee also recognized that Idaho's reliance on low cost coal plants may become a source of risk in the future due to the economic impact of potential federal regulation of carbon and mercury emissions. To address these concerns, the Committee recommended increasing investments in energy conservation and in-state renewable resources. In a resource priority policy statement, the Committee stated, "When acquiring resources, Idaho and Idaho utilities should give priority to: 1) Conservation, energy efficiency and demand response; and 2) Renewable resources; recognizing that these alone may not fulfill Idaho's growing energy requirements." The Committee further stated, "…energy suppliers must continue to have access to conventional energy resources to keep Idaho's energy costs as low as possible."

The Committee also expressed support for the "25x'25" vision which states: "By 2025, America's farms, forests and ranches will

provide 25% of the total energy consumed in the United States, while continuing to produce safe, abundant, and affordable food, feed and fiber." Additional information regarding the "25x'25" vision can be found at www.25x25.org.

### *Oregon Renewable Portfolio Standard*

The State of Oregon's Renewable Portfolio Standard (RPS) requires utilities and electricity service suppliers serving Oregon load to include in their portfolio of power sold to retail customers a percentage of electricity generated from qualifying renewable energy sources. Oregon's RPS, like most states, is phased in over a number of years with final targets set for the year 2025. The Oregon RPS also includes a tiered system based on the amount of load a utility serves in Oregon. Larger utilities have higher RPS requirements and interim targets while smaller utilities have less rigorous requirements and no interim targets.

Under the Oregon RPS, Idaho Power is categorized as a "smaller utility" because the percentage of the company's retail electric sales in Oregon are between 1.5 and 3% of the total retail sales in the state (less than 5% of Idaho Power's total load is in Oregon). As a "smaller utility" Idaho Power is not subject to interim targets, however, by 2025 at least 10% of Idaho Power's retail sales in Oregon must come from qualifying renewable energy sources.

## Fixed Cost Adjustment

On January 27, 2006, Idaho Power filed an application with the Idaho PUC requesting the authority to implement a Fixed Cost Adjustment (FCA) mechanism similar to the Power Cost Adjustment (PCA). The FCA is designed to adjust rates downward or upward to recover fixed costs independent of the volume of the company's energy sales. The filing was a continuation of a 2004 case that was opened to investigate the financial disincentives to investment in energy efficiency by Idaho Power.

Idaho Power and the Idaho PUC staff agreed in concept to a three-year pilot program beginning January 1, 2007, and a stipulation was filed on December 18, 2006. The stipulation called for the implementation of the FCA mechanism pilot program as proposed by the company in its original application with additional conditions and provisions related to customer count and weather normalization methodology, recording of the FCA deferral amount in reports to the Idaho PUC and detailed reporting of DSM activities. The Idaho PUC approved the stipulation on March 12, 2007. The pilot program retroactively began on January 1, 2007, and will run through 2009. The first rate adjustment will occur on June 1, 2008, and subsequent rate adjustments will occur on June 1 of each year thereafter during the term of the pilot program.

## Wind Integration Study

Under the Public Utility Regulatory Policies Act (PURPA), Idaho Power is required to offer independent developers a power purchase contract based on a standard avoided cost rate for a qualifying facility with a monthly output of 10 aMW or less. Because a large number of wind project developers came to Idaho Power requesting PURPA contracts in early 2005, Idaho Power requested and the Idaho PUC granted temporary relief from PURPA requirements until the impact of wind integration could be studied. The Idaho PUC granted relief by temporarily reducing the PURPA cap of 10 aMW to 100 kW for PURPA wind projects.

On February 6, 2007, Idaho Power filed a wind integration study report with the Idaho PUC. Idaho Power also filed a petition requesting removal of the temporary restriction on the size of PURPA wind projects and an adjustment to the avoided cost rates to compensate for the increase in system costs due to wind variability.

On March 15, 2007, and June 20, 2007, public workshops were held to present and discuss the results of the wind integration study.

Following negotiations to settle the case, Idaho Power entered into a settlement stipulation on October 2, 2007. The settlement stipulation prescribed a methodology for calculating a wind integration charge that will be applied to PURPA wind projects as well as other provisions. The integration charge will be calculated as a percentage of the current 20-year, levelized, avoided cost rate and be subject to a cap of $6.50 per MWh. On February 20, 2008, the Idaho PUC issued an order approving the settlement stipulation and returned the PURPA cap to 10 aMW.

## FERC Relicensing Process

Idaho Power, like other utilities that operate non-federal hydroelectric projects on qualified waterways, obtains licenses for its hydroelectric projects from the Federal Energy Regulatory Commission (FERC). The licenses last for 30 to 50 years depending on the size, complexity, and cost of the project. Idaho Power is actively pursuing the relicensing of the Hells Canyon Complex and Swan Falls projects.

The most significant ongoing relicensing effort is the Hells Canyon Complex (HCC). The HCC provides approximately two-thirds of Idaho Power's hydroelectric generating capacity and 40% of the company's total generating capacity. The current license for the HCC expired at the end of July 2005. Until the new multi-year license is issued, Idaho Power continues to operate the project under an annual license issued by the FERC.

The license application was filed in July 2003 and accepted by the FERC for filing in December 2003. The FERC is now processing the application consistent with the requirements of the Federal Power Act (FPA), the National Environmental Policy Act of 1969, as amended (NEPA), the Energy Policy Act and other applicable federal laws.

The license for the Swan Falls hydroelectric project expires in June 2010. On March 10, 2005, Idaho Power issued a Formal Consultation Package (FCP) to the public relating to environmental studies designed to determine project effects for the relicensing of the project. On September 21, 2007, Idaho Power submitted a draft license application to the FERC for public review and comment. The draft application is based on the results of the environmental studies along with agency and public consultation. Idaho Power will file a final license application for the Swan Falls hydroelectric project with the FERC in June 2008.

Failure to relicense any of the existing hydropower projects at a reasonable cost will create upward pressure on the current electric rates of Idaho Power customers. The relicensing process also has the potential to decrease available capacity and increase the cost of a project's generation through additional operating constraints and requirements for environmental protection, mitigation, and enhancement (PM&E) imposed as a condition for relicensing. Idaho Power's goal throughout the relicensing process is to maintain the low cost of generation at the hydroelectric facilities while implementing non-power measures designed to protect and enhance the river environment.

No reduction of the available capacity or operational flexibility of the hydroelectric plants to be relicensed was assumed as part of the 2006 IRP. If capacity reductions or reductions in operational flexibility do occur as a result of the relicensing process, Idaho Power will adjust future resource plans to reflect the need for additional capacity resources in order to maintain the existing level of reliability.

## Renewable Energy Credits (Green Tags)

A renewable energy credit (REC) or "green tag" is a tradable commodity that is created for each megawatt-hour of energy generated from a qualified renewable energy project. Traditional carbon emissions trading programs promote low-carbon technologies by increasing the cost of emitting carbon, while RECs create incentives to develop carbon-neutral renewable energy resources by providing a production subsidy.

Idaho Power has enrolled in the Western Renewable Energy Generation Information System (WREGIS). WREGIS was developed by the Western Electricity Coordination Council (WECC) in cooperation with numerous utility, governmental and environmental groups to provide a universal, independent, REC tracking system. Since its inception in late 2007, WREGIS has quickly become the tracking system preferred by many western states and regulatory agencies.

Idaho Power is receiving all the RECs from the Elkhorn Valley Wind Project over the 20-year term of the power purchase agreement. During initial start-up and testing of the project in late 2007, approximately 16,933 RECs were generated and Idaho Power expects to receive approximately 300,000 RECs from the Elkhorn Valley Wind Project each year beginning in 2008.

Idaho Power will be receiving RECs from up to 3 MW of generation at the Raft River Geothermal Project (Unit 1) when the actual generation of the project exceeds 10 MW. Idaho Power expects to receive approximately 19,000 RECs each year throughout the 25-year term of the power purchase agreement. The project is currently working through initial start up issues and has not routinely exceeded 10 MW. However, Idaho Power expects to receive RECs from the Raft River project starting later in 2008.

Idaho Power continues to review the eligibility of the company's existing resources to create RECs as well as the possibility of acquiring RECs from qualifying facilities under existing and future PURPA contracts. Numerous discussions have been conducted both internally and with the Idaho PUC staff to gather input regarding the development of an Idaho Power REC Policy.

## PURPA Contracts

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), Idaho Power is required to offer independent developers a power purchase contract based on a standard avoided cost rate for any qualifying facility with a monthly output of 10 aMW or less. Because Idaho Power cannot accurately predict the level of future PURPA development, only contracts that are currently signed and approved by the Idaho PUC are included in Idaho Power's resource plans.

Since the 2006 IRP was published, the overall expected nameplate rating of PURPA projects has not changed materially. Changes that have taken place include reductions of 26.9 MW from two biomass projects, 19.5 MW from one wind project and 10 MW from a geothermal project. Additions since the 2006 IRP include 57.6 MW from three wind projects. These adjustments result in a cumulative change in the contract nameplate rating from 438.2 MW in 2006 to 439.4 MW today. Idaho Power currently has 94 signed and approved PURPA contracts.

## Wholesale Contracts

Idaho Power currently has one, fixed-term, off-system sales contract to supply 6 aMW to the Raft River Rural Electric Cooperative. Since the 2006 IRP was published, the term of the contract has been renewed annually and is

expected to continue to be renewed through the end of September 2011.

The Raft River Cooperative is the electric distribution utility serving Idaho Power's former customers in Nevada and the agreement was established as a full-requirements contract after being approved by the FERC and the Public Utilities Commission of Nevada.

The contract that Idaho Power had to supply 6 aMW to the City of Weiser expired at the end of 2006. The expiration of this contract was anticipated in the 2006 Integrated Resource Plan.

Idaho Power and Montana's NorthWestern Energy negotiated a load-following agreement in which Idaho Power provided NorthWestern Energy 30 MW of load-following service. Idaho Power did not renew the load-following agreement at the end of 2007 because of concerns regarding the integration of more than 350 MW of wind generation anticipated to be interconnected on Idaho Power's system.

NorthWestern has provided load following services for the Salmon, Idaho area which is located in the NorthWestern Balancing Authority Area. Idaho Power and NorthWestern are currently working together to move the Salmon area load into the Idaho Power Balancing Authority Area.

Idaho Power continues to utilize its transmission capacity on the Jefferson line to import power from Montana during the summer months. At present, Idaho Power purchases 83 MW during heavy load hours from June through August from PPL Montana. Although the purchase agreement expires in August 2009, Idaho Power plans to continue to utilize the available transmission capacity during the summer months. An RFP has been issued to supply 83 MW for the three summer months beginning in June 2010 and proposals are due in May 2008.

# 3. Planning Period Forecasts

## Sales and Load Forecast

In addition to the biennial IRP process, Idaho Power prepares a sales and load forecast each calendar year as part of the company's annual financial forecast. The sales and load forecast is strongly influenced by the most recently available economic forecast developed by Idaho Economics, an independent consultant. The forecast of the number of households and employment projections, along with customer consumption patterns, is used to develop customer forecasts and load projections. The projections were updated in August 2007 and are the basis for the sales and load forecast for the 2008 IRP Update.

Significant factors influencing the 2008 IRP Update sales and load forecast include:

- The sales and load forecast developed for the 2008 IRP Update reflects the addition of one new "Special Contract" customer. This customer plans to begin operation in January 2009 and reach full capacity by August 2009. The 2008 IRP Update sales and load forecast includes 38 aMW with a peak demand of 43 MW for this customer. Although this additional load was included in the updated forecast, Idaho Power and the customer are still in discussions and the final load could eventually be more than double these amounts.

- Demand-side management (DSM) program performance has exceeded the 2006 IRP projections.

- The effect of code changes for residential building practices, including increased insulation requirements and air conditioning unit efficiency for new construction and replacement units, has lowered energy consumption projections.

- New DSM programs proposed in the 2006 IRP were initially categorized as supply-side resources. As proposed programs are implemented, the program effects are integrated into existing DSM and considered to be part of the load forecast base which lowers the energy and peak forecast. The 2008 IRP Update sales and load forecast reflects the full integration of DSM program effects as a reduction to the forecast time series as well as the effects of new building codes and air conditioning efficiency standards.

### *Customer and Load Growth*

Customer growth is the primary factor leading to Idaho Power's need for additional resources. Population growth throughout southern Idaho - specifically in the Treasure Valley - requires additional resources to meet both the instantaneous peak and the sustained energy needs of the new customers. As mentioned in the 2006 IRP, new generation is often more costly than electricity produced at existing facilities. Incorporating new generation in Idaho Power's rate base tends to increase electricity prices for all customers in all rate classes.

In 1990, Idaho Power had approximately 290,000 retail customers. Today, Idaho Power serves more than 480,000 retail customers in Idaho and Oregon. Firm peak-hour load has increased from less than 2,100 MW in 1990 to nearly 3,200 MW in the summer of 2007. In July 2007, the peak-hour load reached 3,193 MW, which was a new system record. Average firm load has increased from 1,200 aMW in 1990 to 1,800 aMW at the end of 2007. A summary of Idaho Power's load and customer data is shown in Table 1.

The sales and load forecast anticipates that Idaho Power will add between 12,500 and 13,000 new customers each year throughout the planning period. The annual compound growth rate is approximately 2.1%. The compound growth rate results in expected customer growth from approximately 480,500 customers in 2007 to nearly 740,000 customers in 2027. Figure 1 shows a comparison of the 2006 and 2008 updated customer forecasts. Figure 1 shows that there will be a greater number of retail customers than were forecast in the 2006 IRP - nearly 26,000 more retail customers by 2027. The additional 26,000 retail customers represent a change in total customers of almost 4% by the end of the 20-year planning period.

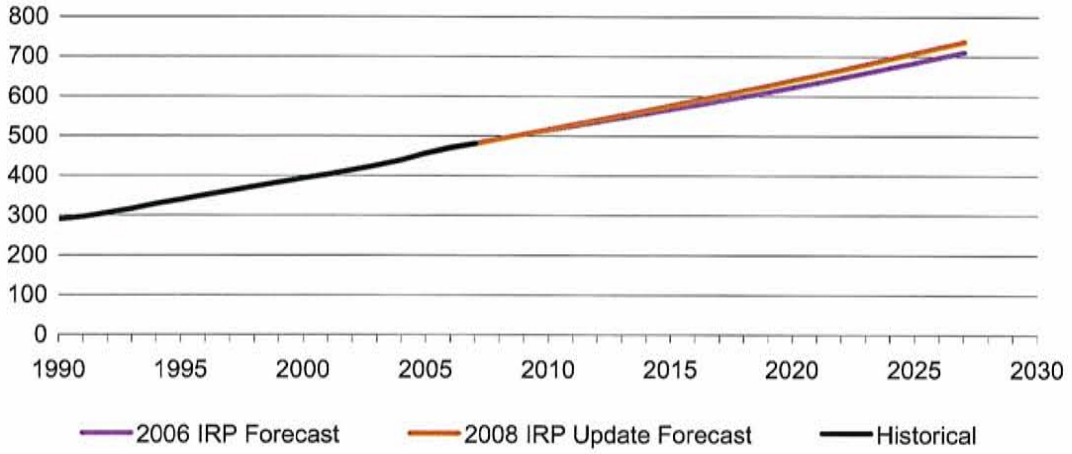
The recent cyclical slowdown in customer growth, as indicated in the total number of customers for year end 2007 is approximately three tenths of a percent lower than forecast (0.3%). The effect of the cyclical downturn on the longer term trend will be evaluated for the 2009 IRP.

**Table 1. Historical Data (1990-2007)**

| Year | Peak Firm Load (MW) | Average Firm Load (aMW) | Number of Customers | Change in Customers from Previous Years |
|---|---|---|---|---|
| 1990 | 2,052 | 1,205 | 290,492 | 7,327 |
| 1991 | 1,972 | 1,206 | 296,584 | 6,092 |
| 1992 | 2,164 | 1,281 | 306,292 | 9,708 |
| 1993 | 1,935 | 1,274 | 316,564 | 10,272 |
| 1994 | 2,245 | 1,375 | 329,094 | 12,530 |
| 1995 | 2,224 | 1,324 | 339,450 | 10,356 |
| 1996 | 2,437 | 1,438 | 351,261 | 11,811 |
| 1997 | 2,352 | 1,457 | 361,838 | 10,577 |
| 1998 | 2,535 | 1,491 | 372,464 | 10,626 |
| 1999 | 2,675 | 1,552 | 383,354 | 10,890 |
| 2000 | 2,765 | 1,653 | 393,095 | 9,741 |
| 2001 | 2,500 | 1,576 | 403,061 | 9,966 |
| 2002 | 2,963 | 1,622 | 414,062 | 11,001 |
| 2003 | 2,944 | 1,657 | 425,599 | 11,537 |
| 2004 | 2,843 | 1,671 | 438,912 | 13,313 |
| 2005 | 2,961 | 1,660 | 456,104 | 17,192 |
| 2006 | 3,084 | 1,745 | 470,950 | 14,846 |
| 2007 | 3,193 | 1,808 | 480,523 | 9,573 |

**Figure 1. Retail Customers**

*(thousands of customers)*



## Load Forecast

Alternate forecast scenarios for average load and peak-hour load were developed for the 2006 IRP. The two planning criteria, the 70th percentile average load for energy planning, and the 95th percentile peak-hour load for capacity planning, have not been changed in the 2008 IRP Update.

The projected demand for electricity by customers in Idaho Power's service area is bounded by high and low probabilistic load forecasts. The boundary forecasts reflect the range of load uncertainty associated with alternate weather related assumptions. The median forecast is between the two boundaries and Idaho Power considers the median forecast to represent the most likely outcome.

Both the average energy and the peak-hour load forecasts have declined since the 2006 IRP. A variety of factors have contributed to the load forecast change. The customer forecast has increased since publishing the 2006 IRP and the customer increase leads to an increase in both peak-hour and average energy. Offsetting the energy increase are the effects of the DSM programs and a forecast increase in retail electricity prices. Two factors affect the DSM projections. First, the DSM programs have been more effective than forecast in the 2006 IRP – the DSM program results have exceeded the projections made in 2006. And second, is the manner in which Idaho Power treats the DSM projections in an IRP. In an IRP, new DSM programs are added to the resource stack meaning demand-side programs are treated equally with supply-side resources. However, when a demand-side program is initiated and Idaho Power commits to the program, the program effects are considered as part of the load forecast. Unlike demand-side programs, the effects of existing and committed supply-side resources continue to be analyzed as part of the resource stack. The final factor contributing to the decline in the sales and load forecast is that energy prices are forecast to increase slightly faster than originally projected in the 2006 IRP, which is expected to result in a slight reduction in energy consumption.

## Average Load (Energy)

Table 2 summarizes three forecast outcomes of Idaho Power's estimate of its annual system load considering median, 70th percentile and 90th percentile weather impacts on the expected (median) load forecast. The 70th percentile forecast is based on 70th percentile weather to determine average monthly load which means three years out of ten would exceed the forecast.

Idaho Power uses the 70th percentile forecast as the basis for energy resource planning. Therefore, the planning criteria for determining

**Table 2. Range of System Load Growth Forecasts (aMW) 2008 IRP Update**

| Year | Median | 70th Percentile | 90th Percentile |
|---|---|---|---|
| 2007 **(Actual)** | **1,810** | **1,810** | **1,810** |
| 2008 | 1,812 | 1,853 | 1,925 |
| 2009 | 1,880 | 1,921 | 1,994 |
| 2010 | 1,913 | 1,955 | 2,029 |
| 2011 | 1,941 | 1,984 | 2,059 |
| 2012 | 1,954 | 1,997 | 2,073 |
| 2013 | 1,976 | 2,020 | 2,097 |
| 2014 | 1,989 | 2,034 | 2,112 |
| 2015 | 2,008 | 2,053 | 2,132 |
| 2016 | 2,036 | 2,081 | 2,162 |
| 2017 | 2,051 | 2,097 | 2,178 |
| 2018 | 2,067 | 2,114 | 2,196 |
| 2019 | 2,096 | 2,144 | 2,227 |
| 2020 | 2,129 | 2,176 | 2,261 |
| 2021 | 2,163 | 2,211 | 2,297 |
| 2022 | 2,197 | 2,246 | 2,333 |
| 2023 | 2,231 | 2,280 | 2,368 |
| 2024 | 2,265 | 2,314 | 2,403 |
| 2025 | 2,301 | 2,351 | 2,441 |
| 2026 | 2,341 | 2,392 | 2,483 |
| 2027 | 2,380 | 2,432 | 2,524 |
| Growth Rate *(2005–2027)* | 1.4% | 1.4% | 1.4% |

the need for energy resources assumes 70th percentile average load conditions. The projected 20-year average annual compound growth rate in the expected load forecast is 1.4% and average energy demand is forecast to grow at about 30 aMW per year. Figure 2 illustrates the 70th percentile average load forecasts used in the 2006 IRP and 2008 IRP Update. The difference between the two forecasts is shown in Table 3.

## Peak-Hour Load

New housing growth and the associated increase in air conditioning load in southern Idaho is driving much of Idaho Power's peak-hour load growth. In the updated load forecast, the peak-hour load is projected to grow by approximately 70 MW per year throughout the planning period, which is 10 MW per year less than predicted in the 2006 IRP. This reduction in the growth rate is due to DSM demand response programs, local and federal efficiency codes and standards, and reduced consumption due to higher prices.

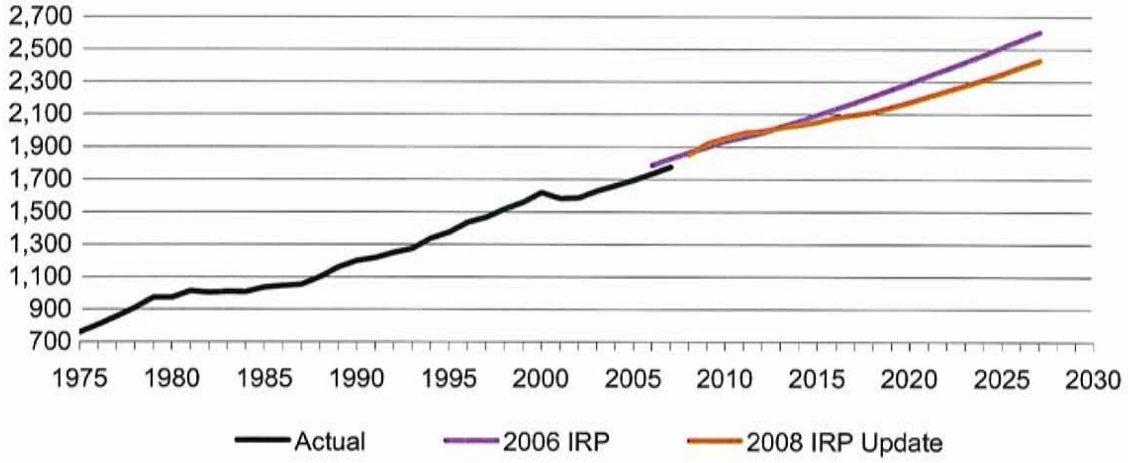
Table 4 summarizes three forecast outcomes of Idaho Power's estimate of its annual system peak considering median, 90th percentile and 95th percentile weather impacts on the expected (median) peak forecast. The 95th percentile forecast uses the 95th percentile peak day temperature to determine monthly peak-hour

**Table 3. Change in System Load Growth (aMW) 2008 IRP Update vs. 2006 IRP**

| Year | Median | 70th Percentile | 90th Percentile |
|---|---|---|---|
| 2008 | -10 | -11 | -10 |
| 2009 | 23 | 22 | 22 |
| 2010 | 21 | 20 | 21 |
| 2011 | 23 | 23 | 23 |
| 2012 | 12 | 11 | 12 |
| 2013 | -2 | -3 | -2 |
| 2014 | -25 | -25 | -24 |
| 2015 | -43 | -44 | -43 |
| 2016 | -53 | -54 | -51 |
| 2017 | -77 | -77 | -76 |
| 2018 | -100 | -100 | -98 |
| 2019 | -111 | -111 | -109 |
| 2020 | -119 | -119 | -116 |
| 2021 | -127 | -127 | -124 |
| 2022 | -136 | -135 | -132 |
| 2023 | -145- | -145 | -142 |
| 2024 | -154 | -155 | -152 |
| 2025 | -163 | -164 | -160 |
| 2026 | -168 | -168 | -165 |
| 2027 | -175 | -175 | -172 |
| % Change *(in 2027)* | -6.8% | -6.7% | -6.4% |

**Figure 2. Forecasted Firm Load – 70th Percentile**

*(average megawatts)*



demand. Idaho Power uses the 95th percentile forecast as the basis for peak resource planning. Therefore, the planning criteria for determining the need for peak-hour capacity assumes 95th percentile peak-day temperature conditions.

**Table 4. Range of System Peak Growth Forecasts (MW) 2008 IRP Update**

| Year | Median | 90th Percentile | 95th Percentile |
|---|---|---|---|
| 2007 **(Actual)** | **3,193** | **3,193** | **3,193** |
| 2008 | 3,099 | 3,240 | 3,284 |
| 2009 | 3,193 | 3,338 | 3,383 |
| 2010 | 3,252 | 3,400 | 3,446 |
| 2011 | 3,313 | 3,464 | 3,511 |
| 2012 | 3,356 | 3,510 | 3,558 |
| 2013 | 3,409 | 3,567 | 3,617 |
| 2014 | 3,454 | 3,615 | 3,666 |
| 2015 | 3,506 | 3,671 | 3,723 |
| 2016 | 3,572 | 3,740 | 3,793 |
| 2017 | 3,620 | 3,792 | 3,846 |
| 2018 | 3,672 | 3,847 | 3,901 |
| 2019 | 3,738 | 3,916 | 3,972 |
| 2020 | 3,808 | 3,990 | 4,047 |
| 2021 | 3,881 | 4,066 | 4,124 |
| 2022 | 3,955 | 4,143 | 4,202 |
| 2023 | 4,028 | 4,220 | 4,280 |
| 2024 | 4,103 | 4,298 | 4,359 |
| 2025 | 4,179 | 4,378 | 4,440 |
| 2026 | 4,262 | 4,464 | 4,527 |
| 2027 | 4,345 | 4,550 | 4,615 |
| Growth Rate *(2008-2027)* | 1.8% | 1.8% | 1.8% |

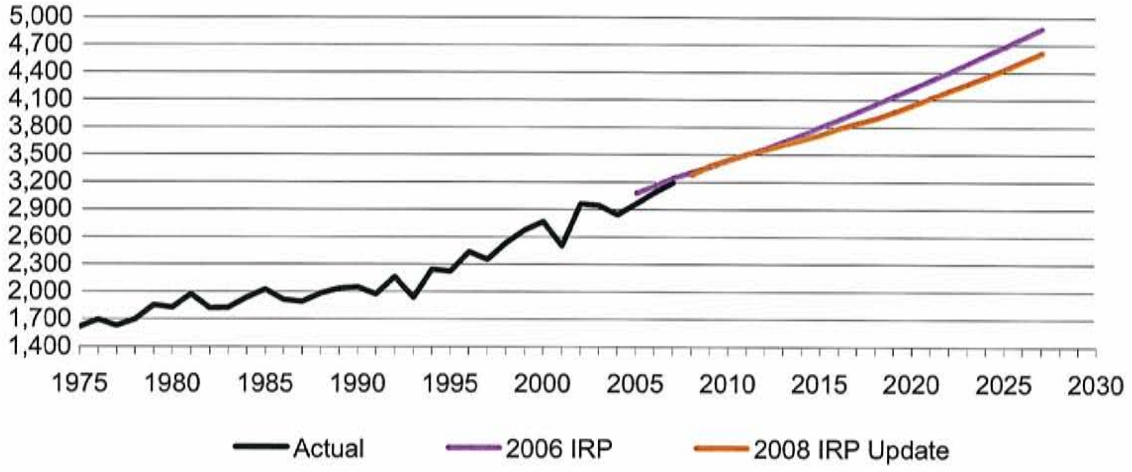
The projected 20-year average annual compound growth rate in the expected peak forecast is 1.8% as shown in Table 4. Figure 3 illustrates the 95th percentile system peak forecasts used in the 2006 IRP and 2008 IRP Update. The difference between the two forecasts is shown in Table 5.

**Table 5. Change in System Peak Growth (MW) 2008 IRP Update**

| Year | Median | 90th Percentile | 95th Percentile |
|---|---|---|---|
| 2008 | -28 | -28 | -28 |
| 2009 | 11 | 12 | 11 |
| 2010 | 4 | 4 | 4 |
| 2011 | 5 | 5 | 5 |
| 2012 | -11 | -12 | -12 |
| 2013 | -30 | -30 | -30 |
| 2014 | -57 | -58 | -57 |
| 2015 | -83 | -83 | -82 |
| 2016 | -95 | -96 | -95 |
| 2017 | -127 | -127 | -126 |
| 2018 | -156 | -156 | -157 |
| 2019 | -172 | -172 | -172 |
| 2020 | -185 | -185 | -184 |
| 2021 | -197 | -197 | -197 |
| 2022 | -209 | -209 | -209 |
| 2023 | -223 | -223 | -223 |
| 2024 | -236 | -236 | -236 |
| 2025 | -249 | -249 | -249 |
| 2026 | -256 | -256 | -256 |
| 2027 | -265 | -266 | -265 |
| % Change *(in 2027)* | -5.7% | -5.5% | -5.4% |

**Figure 3. Forecasted Firm Summer Peak – 95th Percentile**

*(megawatts)*



## Hydroelectric Generation Forecast

In the IRP process, Idaho Power assesses resource adequacy using the 70th percentile water condition for average energy planning and the more constrained 90th percentile water condition for peak-hour planning. Idaho Power recognizes that water management issues in the Snake River drainage will continue to remain the subject of debate for the foreseeable future and the company will adjust the hydroelectric resource projections in the IRP in response to changing practices and conditions.

### *Water Issues in Idaho*

Power generation at Idaho Power's hydroelectric projects on the Snake River is dependent upon the state water rights held by the company and the long-term sustainability of the Snake River, tributary spring flows and the Eastern Snake Plain Aquifer that is connected to the Snake River. Idaho Power continues to participate in the water management issues in Idaho that may affect the company's water rights and resources.

One of the main water rights issues facing Idaho Power Company is the Snake River Basin Adjudication initiated in 1987. The Snake River Adjudication is a legal action containing both judicial and administrative proceedings. The adjudication process will allocate the Snake River water between surface water users, ground water users, in-stream non-consumptive water users, senior water rights holders, and junior water rights holders. The objective of the Snake River Basin Adjudication is to reverse the decline in river, spring, and aquifer water levels and to address the long-term water resource needs of the state.

Idaho Power will continue to vigorously defend its water rights. None of the pending water management issues are expected to impact Idaho Power Company hydroelectric generation in the near-term, but the company cannot predict the ultimate outcome of the legal and administrative water rights proceedings. Idaho Power's ongoing participation in water rights issues is to guarantee that sufficient water is available for use at the company's hydroelectric projects on the Snake River.

### *Flow Augmentation*

Reports issued in 2007 by the Bureau of Reclamation (August 2007) and NOAA Fisheries Service (October 2007) suggest an intent to explore shifting the delivery of flow augmentation water from the months of July and August to the spring months of April, May and June. A follow-up biological opinion report is anticipated later in 2008.

Idaho Power has performed a preliminary resource planning analysis to estimate the impact of the shift in the timing of the flow augmentation water. The analysis suggests that under the 70th percentile water condition used for energy resource planning, generation levels for the most energy constrained month (July) are projected to decline by approximately 115 aMW. Idaho Power will continue to monitor the issue to ensure that generation projections for its hydroelectric facilities for the 2009 IRP are consistent with current federal flow augmentation practices and schedules.

## Coal Price Forecast

The expected coal price forecast developed for the 2006 IRP was an average of Idaho Power's coal forecasts for its Valmy and Jim Bridger thermal plants. In addition, the 2006 IRP used a Wyoming specific coal forecast for potential generation resources located in Wyoming and a regional coal price forecast for resources at non-specific locations. The coal price forecasts were created using coal and rail transportation market information, private forecasts, and the Global Insight 2006 U.S. Power Outlook report. The resulting costs in dollars per MMBtu represent the delivered cost of the coal, including rail costs, coal costs, and use taxes.

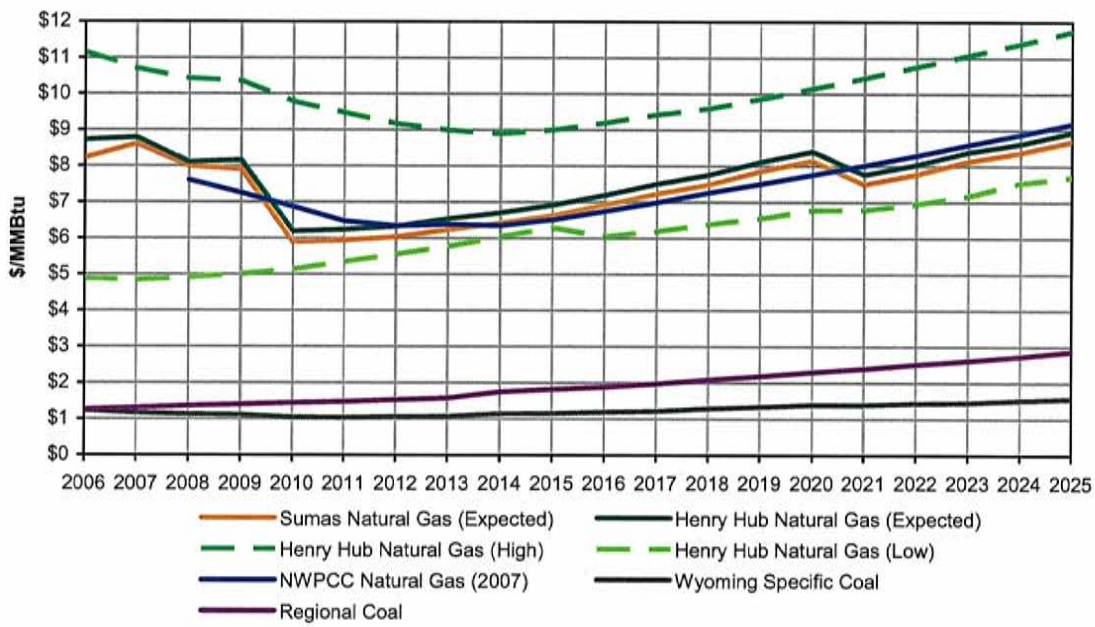
In general, coal prices have risen due to increases in the cost of diesel fuel, explosives, utilities, shipping and other consumables used in mining. The coal price forecasts were not updated as part of the 2008 IRP Update, however, new forecasts will be prepared in 2008 as part of the 2009 IRP process. A summary of both coal price forecasts used in the 2006 IRP are shown in Table 6 and Figure 4.

## Natural Gas Price Forecast

Idaho Power does not directly forecast natural gas prices as part of the planning process. Industry forecasts developed by outside consultants are combined with forecasts from published sources to create a composite forecast. The expected gas price forecast used in the IRP is derived from public and private source forecasts including IGI Resources, NYMEX, PIRA, EIA, NWPCC, and U.S. Power Outlook. The forecast from each source is converted to nominal dollars and then converted to dollars per MMBtu at the Sumas trading hub. Each forecast is then weighted and used to develop the composite forecast. Transportation costs are then added to the weighted average price to develop a final estimate of the delivered cost in dollars per MMBtu. The transportation costs also include Northwest Pipeline's fixed and volumetric charges as well as fuel gas.

**Figure 4. 2006 IRP Fuel Forecast**

*(Nominal $/MMBtu)*



Idaho Power has not prepared an updated natural gas price forecast for the 2008 IRP Update. However, the Northwest Power and Conservation Council (NWPCC) recently issued a revised natural gas price forecast which is shown in Table 6 and Figure 4 along with the forecasts used in Idaho Power's 2006 IRP. As shown in Figure 4, the new forecast from the NWPCC does not deviate materially from Idaho Power's expected case forecast used in the 2006 IRP.

**Table 6. Coal and Natural Gas Forecasts**
**($/MMBtu Delivered–Nominal)**

| Year | 2006 IRP Wyoming Specific Coal[1] | 2006 IRP Regional Coal[2] | 2006 IRP Sumas Natural Gas (Expected) | 2006 IRP Henry Hub Natural Gas (Expected) | 2006 IRP Henry Hub Natural Gas (High) | 2006 IRP Henry Hub Natural Gas (Low) | 2007 NWPCC Natural Gas Price Forecast |
|---|---|---|---|---|---|---|---|
| 2006 | $1.24 | $1.27 | $8.23 | $8.73 | $11.16 | $4.89 | |
| 2007 | $1.17 | $1.32 | $8.62 | $8.79 | $10.71 | $4.86 | |
| 2008 | $1.13 | $1.37 | $8.00 | $8.11 | $10.43 | $4.92 | $7.58 |
| 2009 | $1.11 | $1.41 | $7.91 | $8.17 | $10.36 | $5.01 | $7.20 |
| 2010 | $1.05 | $1.45 | $5.90 | $6.19 | $9.79 | $5.14 | $6.80 |
| 2011 | $1.03 | $1.49 | $5.95 | $6.24 | $9.48 | $5.35 | $6.38 |
| 2012 | $1.06 | $1.53 | $6.04 | $6.33 | $9.18 | $5.57 | $6.23 |
| 2013 | $1.07 | $1.58 | $6.24 | $6.53 | $9.00 | $5.78 | $6.30 |
| 2014 | $1.14 | $1.75 | $6.42 | $6.71 | $8.90 | $6.05 | $6.30 |
| 2015 | $1.15 | $1.83 | $6.64 | $6.92 | $9.01 | $6.30 | $6.53 |
| 2016 | $1.19 | $1.90 | $6.92 | $7.20 | $9.20 | $6.05 | $6.82 |
| 2017 | $1.22 | $1.98 | $7.23 | $7.50 | $9.43 | $6.20 | $7.10 |
| 2018 | $1.29 | $2.09 | $7.49 | $7.75 | $9.60 | $6.40 | $7.44 |
| 2019 | $1.34 | $2.19 | $7.86 | $8.12 | $9.87 | $6.56 | $7.71 |
| 2020 | $1.40 | $2.31 | $8.16 | $8.41 | $10.16 | $6.79 | $8.00 |
| 2021 | $1.39 | $2.41 | $7.51 | $7.77 | $10.45 | $6.80 | $8.28 |
| 2022 | $1.43 | $2.52 | $7.79 | $8.04 | $10.76 | $6.96 | $8.58 |
| 2023 | $1.45 | $2.63 | $8.14 | $8.39 | $11.08 | $7.18 | $8.89 |
| 2024 | $1.52 | $2.74 | $8.38 | $8.62 | $11.40 | $7.54 | $9.22 |
| 2025 | $1.56 | $2.88 | $8.70 | $8.94 | $11.74 | $7.69 | $9.54 |

[1] Used in the 2006 IRP for a Wyoming Specific coal resource.

[2] Used in the 2006 IRP for a non-location specific, regional coal resource.

[3] NWPCC medium case (east-side delivered) inflated at 2.5%.

# 4. Demand-Side Management

## Demand Side Resources

During 2007, Idaho Power continued to expand the programs that were implemented as a result of the 2004 IRP. Idaho Power's 2006 IRP included the addition of three new DSM programs and the expansion of one program. In addition to the DSM programs identified in the IRP, Idaho Power has also continued to pursue other customer-focused DSM initiatives, including programs that preceded the 2004 IRP, educational opportunities, and regional market transformation efforts. As part of new regulatory initiatives, in 2007 Idaho Power committed to enhance its efforts to promote energy efficiency.

Idaho Power's DSM activities throughout 2007 were primarily focused on enhanced program participation and energy savings in the current programs, and design and implementation of new programs. Idaho Power has also continued to integrate the company's field and support personnel to increase customer awareness and participation in the programs.

### *Program Performance*

Demand-side management programs at Idaho Power continue to grow as measured by customer participation, energy savings, and demand reduction. In 2007, participation in the A/C Cool Credit program increased by 155%. The Irrigation Peak Rewards and A/C Cool Credit programs resulted in an estimated combined summer peak reduction of 48 MW, representing a 29% increase from 2006 results. The four energy efficiency programs that were identified in the 2004 IRP are the Custom Efficiency (Industrial), Building Efficiency (Commercial), ENERGY STAR® Homes Northwest (Residential), and Irrigation Efficiency Rewards programs. The four programs resulted in total annual savings of over 45,000 MWh in 2007, which was a 20% increase over the 2006 energy savings of approximately 38,000 MWh for the same programs. The energy efficiency programs that originated as a result of the 2006 IRP are the Heating and Cooling Efficiency (Residential), ENERGY STAR® Lighting (Residential), and the Easy Upgrades (Commercial) programs. The new programs resulted in annual savings of over 12,000 MWh in 2007.

An expansion of the program formerly known as the Industrial Efficiency program was also identified in the 2006 IRP. The program was expanded in 2007 and is now called the Custom Efficiency program.

In addition to the IRP programs offered during 2007, Idaho Power operated several other energy efficiency programs targeting residential customers: Weatherization Assistance for Qualified Customers (WAQC), Energy House Calls, Rebate Advantage, and Oregon Residential Weatherization. The energy efficiency programs added annual savings of over 4,500 MWh in 2007.

### *Residential Programs*

Programs available to residential customers include one demand response program, seven energy efficiency programs, and an educational initiative program. The residential demand response program is called "A/C Cool Credit" and the program achieves peak-hour demand reduction by cycling customers' central air conditioners. The residential energy efficiency programs include Energy House Calls, ENERGY STAR® Homes Northwest, Oregon Residential Weatherization, Rebate Advantage, ENERGY STAR® Lighting, WAQC, and Heating and Cooling Efficiency.

The Residential Energy Efficiency Education Initiative began in 2007, which provided educational outreach to Idaho Power residential customers. In addition, the Heating and Cooling

Efficiency program and the Appliance program were under development in 2007.

Idaho Power conducted approximately 20 regional events in partnership with local community retailers to educate and influence consumer purchasing decisions relating to ENERGY STAR® Lighting. Idaho Power increased residential program outreach efforts in 2007 through partnerships with Home Depot, Lowes, Wal-Mart, and other retailers. The partnerships were developed to educate customers across Idaho Power's service area about energy efficient lighting and increase the adoption of energy efficient lighting by residential customers.

Another addition in 2007 was the creation of the www.getpluggedin.com Web site and related radio and TV advertising. The marketing channels were designed to educate customers about various issues facing Idaho Power, and specifically, energy efficiency and the role it plays in planning and managing growth.

## Residential Results

In 2007, residential customers were responsible for a 10% increase in energy savings from 2006 with approximately 11,000 MWh savings in 2006 and over 12,000 MWh in 2007. The peak-hour demand savings from residential customers increased by 74% from 6.5 MW in 2006 to 11.4 MW in 2007. Customer participation in the demand response programs increased by 155% for 2007, and compact fluorescent light (CFL) bulb sales increased by 23%.

## Commercial and Industrial Programs

Three programs targeting different energy efficiency activities are available to Idaho Power's commercial and industrial customers. The newest program offered to these customers, Easy Upgrades, was launched in Idaho in February 2007 and in Oregon in May 2007. The program is designed to deliver energy efficiency and demand-side savings to all existing commercial and industrial customers. Easy Upgrades offers a menu of incentives for lighting, HVAC, motors, building shell, plug loads, and grocery refrigeration. With the launch of the Easy Upgrades program, the Oregon School Efficiency program was discontinued since schools can now participate in the Easy Upgrades program.

The Building Efficiency program for new construction projects achieves energy savings that are cost-effective at the time of construction. The program continues to offer energy-saving improvements for lighting, cooling, building shell, and energy control efficiency options. Both Building Efficiency and Easy Upgrades participants can receive incentives up to $100,000 for any projects completed.

The Custom Efficiency program, formerly the Industrial Efficiency program, was expanded to include large commercial customers in 2007. The program is intended for larger custom projects. Idaho Power continues to offer its Oregon Commercial Audits program to medium and small commercial customers.

## Commercial and Industrial Results

Total annual energy savings for the commercial and industrial programs increased by approximately 88%, from approximately 20,000 MWh in 2006 to nearly 38,000 MWh in 2007.

## Irrigation Programs

Idaho Power currently offers two programs to irrigation customers: Irrigation Peak Rewards, a demand response program designed to decrease peak-hour demand, and Irrigation Efficiency Rewards, an energy efficiency program designed to encourage replacement or

improvement of inefficient systems and components.

## Irrigation Results

The Irrigation Peak Rewards program provided significant peak-hour reductions during the summer of 2007 with an average peak load reduction of nearly 29 MW and a maximum summer peak reduction of over 37 MW. The maximum summer peak-hour reduction was approximately 18% higher in 2007 than in 2006. The peak reduction is due to changes in the program incentive structure, which increased the number of two- and three-day-per week participants.

The Irrigation Efficiency Rewards program also had strong participation in 2007. However, the maturity of the program and the early adoption of the menu options by irrigators have caused a leveling off of projects in 2007. Program redesign, implemented in 2006, offered increased incentive levels and provided a menu option program that is popular with irrigation customers. The total energy savings for 2007 was over 12,000 MWh on 819 projects across Idaho Power's service area.

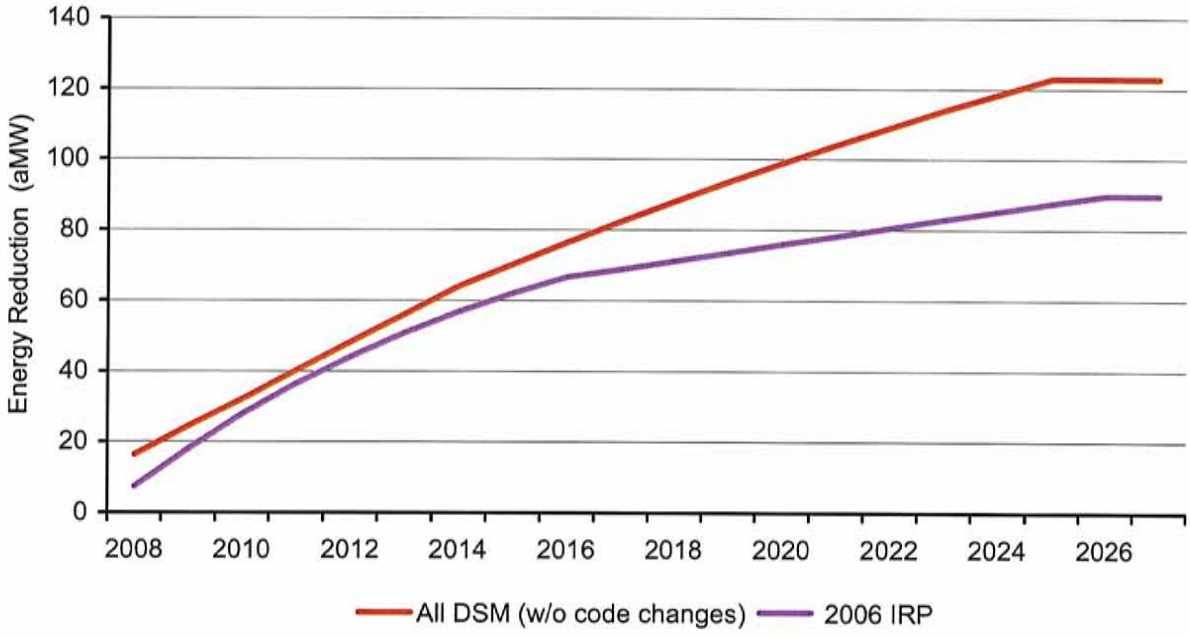
## DSM Future Performance

In 2008, Idaho Power plans to continue to increase participation and energy savings from existing programs, continue to implement new energy efficiency programs, research possible new demand response programs, complete a new DSM potential study, and evaluate several existing programs. Idaho Power also plans to participate in the development of the Northwest Power and Conservation Council's (NWPCC) Sixth Power Plan and to continue enhancing consumer education on energy efficiency.

The effects of DSM programs, changes in Idaho residential building codes, and the federal residential air conditioning unit efficiency standards have been integrated into both the demand-side program forecast and the sales and load forecast included in the 2008 IRP Update. The demand-side programs and their expected effects are addressed in more detail in the company's Demand-Side Management 2007 Annual Report.

Figure 5 shows increased energy savings throughout the planning period in a comparison of the DSM program performance anticipated in

**Figure 5. DSM Forecast Annual Savings**



the 2006 IRP and the 2008 IRP Update. Idaho Power has increased the resources dedicated to energy efficiency and demand response programs, resulting in greater expected program effects. Idaho Power also expects to introduce additional DSM programs throughout the planning period that will result in increased energy savings. The new programs will be considered in the 2009 and subsequent resource plans.

In the later years of the planning period, the updated sales and load forecast shows reduced peak-hour energy consumption resulting from the 2006 IRP demand-side program savings.

The peak-hour reductions are mainly attributed to improved residential building codes and air conditioning standards. For the forecast time period, the 2008 IRP Update forecast shows an overall energy savings improvement of approximately 18% over the earlier forecasts included in the 2006 IRP. Tables 7 and 8 show the effect of DSM on the average and peak-hour load forecasts for the 2008 IRP Update.

The peak-hour load reductions shown in Table 8 are constant from 2010 onward as the present demand response programs reach full implementation. After 2010, new participants are expected to offset program participants who elect to leave the programs. Idaho Power will consider additional demand response programs in the 2009 and subsequent Integrated Resource Plans.

**Table 7. DSM Growth Forecast - 2008 IRP Update vs. 2006 IRP (aMW)**

| | 2008 IRP Update | | | | |
|---|---|---|---|---|---|
| Year | All DSM (w/o Code Changes) | Code Changes | Total DSM | 2006 IRP | Difference |
| 2008 | 16 | 1 | 17 | 7 | 10 |
| 2009 | 25 | 2 | 27 | 18 | 9 |
| 2010 | 32 | 3 | 35 | 28 | 8 |
| 2011 | 40 | 5 | 45 | 37 | 8 |
| 2012 | 48 | 6 | 54 | 44 | 10 |
| 2013 | 56 | 7 | 63 | 51 | 12 |
| 2014 | 64 | 8 | 72 | 57 | 15 |
| 2015 | 70 | 10 | 80 | 62 | 18 |
| 2016 | 77 | 11 | 88 | 67 | 21 |
| 2017 | 83 | 12 | 95 | 69 | 26 |
| 2018 | 88 | 14 | 102 | 71 | 31 |
| 2019 | 94 | 15 | 109 | 74 | 35 |
| 2020 | 99 | 17 | 116 | 76 | 40 |
| 2021 | 104 | 18 | 123 | 78 | 44 |
| 2022 | 109 | 20 | 129 | 81 | 48 |
| 2023 | 114 | 21 | 135 | 83 | 52 |
| 2024 | 118 | 23 | 142 | 85 | 56 |
| 2025 | 123 | 25 | 148 | 88 | 60 |
| 2026 | 123 | 27 | 149 | n/a | n/a |
| 2027 | 123 | 28 | 151 | n/a | n/a |

**Table 8. DSM Peak-Hour Savings - 2008 IRP Update vs. 2006 IRP (MW)**

| | 2008 IRP Update | | 2006 IRP | | Difference | |
|---|---|---|---|---|---|---|
| | Energy Efficiency | Demand Response | Energy Efficiency | Demand Response | Energy Efficiency | Demand Response |
| 2008 | 30 | 66 | 20 | 59 | 10 | 7 |
| 2009 | 46 | 78 | 26 | 73 | 20 | 5 |
| 2010 | 61 | 82 | 32 | 78 | 29 | 5 |
| 2011 | 76 | 82 | 37 | 78 | 39 | 5 |
| 2012 | 92 | 82 | 43 | 78 | 49 | 5 |
| 2013 | 107 | 82 | 48 | 78 | 59 | 5 |
| 2014 | 123 | 82 | 54 | 78 | 69 | 5 |
| 2015 | 135 | 82 | 54 | 78 | 81 | 5 |
| 2016 | 146 | 82 | 54 | 78 | 92 | 5 |
| 2017 | 157 | 82 | 54 | 78 | 103 | 5 |
| 2018 | 168 | 82 | 54 | 78 | 114 | 5 |
| 2019 | 179 | 82 | 54 | 78 | 125 | 5 |
| 2020 | 190 | 82 | 54 | 78 | 136 | 5 |
| 2021 | 200 | 82 | 54 | 78 | 146 | 5 |
| 2022 | 210 | 82 | 54 | 78 | 156 | 5 |
| 2023 | 219 | 82 | 54 | 78 | 166 | 5 |
| 2024 | 229 | 82 | 54 | 78 | 175 | 5 |
| 2025 | 239 | 82 | 54 | 78 | 186 | 5 |
| 2026 | 243 | 82 | n/a | n/a | n/a | n/a |
| 2027 | 247 | 82 | n/a | n/a | n/a | n/a |

# 5. Supply-Side Resources

## Evander Andrews Peaking Resource

Idaho Power began construction of a third simple cycle combustion turbine at the Evander Andrews Power Complex near Mountain Home, Idaho in early 2007. The plant began commercial operations on March 11, 2008. The combustion turbine provides approximately 166 MW of capacity during summer peak-hour loads and up to 200 MW during the winter.

Idaho Power received a Certificate of Public Convenience and Necessity for the project from the Idaho PUC on December 15, 2006. The certificate included a power plant construction cost commitment estimate of $60 million. On March 7, 2008, Idaho Power filed an application with the Idaho PUC for authorization to place $57,650,861 of plant investment into rate base.

The March 7, 2008 filing also included $7,331,116 for investment in transmission and interconnection facilities. These transmission and interconnection facilities, which are complete and in service, will allow the new Evander Andrews combustion turbine to operate this summer. However, an additional $19.5 million of transmission and interconnection facilities are scheduled to be placed in service in October 2008 to improve transmission reliability associated with the new power plant.

## Shoshone Falls Upgrade

On August 17, 2006, Idaho Power filed a license amendment application with the FERC allowing the company to upgrade the Shoshone Falls project from 12.5 MW to 62.5 MW. In March 2007, Idaho Power received a draft Environmental Assessment (EA) and Notice of Ready for Environmental Analysis from the FERC, which provided for a 60-day comment period for interested entities. The FERC issued a supplemental EA on December 4, 2007 and Idaho Power expects that a license amendment will be issued in 2008. In conjunction with the license amendment application, Idaho Power has filed a water rights application which is currently being reviewed by the Idaho Department of Water Resources (IDWR).

## Horizon Wind Energy Power Purchase Agreement

In February 2007, the Idaho PUC approved a power purchase agreement with Telocaset Wind Power Partners, LLC, a subsidiary of Horizon Wind Energy, for 101 MW of nameplate wind generation from the Elkhorn Valley Wind Project located in northeastern Oregon. The Elkhorn Wind project was constructed during 2007 and began commercial operations on December 28, 2007.

## U.S. Geothermal Power Purchase Agreement

The 2006 IRP identified a need for Idaho Power to acquire geothermal generation resources. An RFP (Request for Proposals) for geothermal energy was released on June 2, 2006. Idaho Power identified U.S. Geothermal as the successful bidder in March 2007 based on their proposal to supply 45.5 MW of geothermal energy. On January 9, 2008, the Idaho PUC approved a power purchase agreement for 13 MW of nameplate generation from the Raft River Geothermal Power Plant (Unit 1) located in southern Idaho. Raft River Unit 1 began operating at a lower capacity in October 2007 under a PURPA contract.

Contract negotiations for the remaining 32.5 MW will take place over the next several months and is expected to include an additional unit at the Raft River site and two units at the Neal Hot Springs site located in eastern Oregon. On-line dates for these three projects are uncertain and will depend on the progress of

development activities. However, these projects are not expected to meet the 2009 on-line date identified in the 2006 IRP.

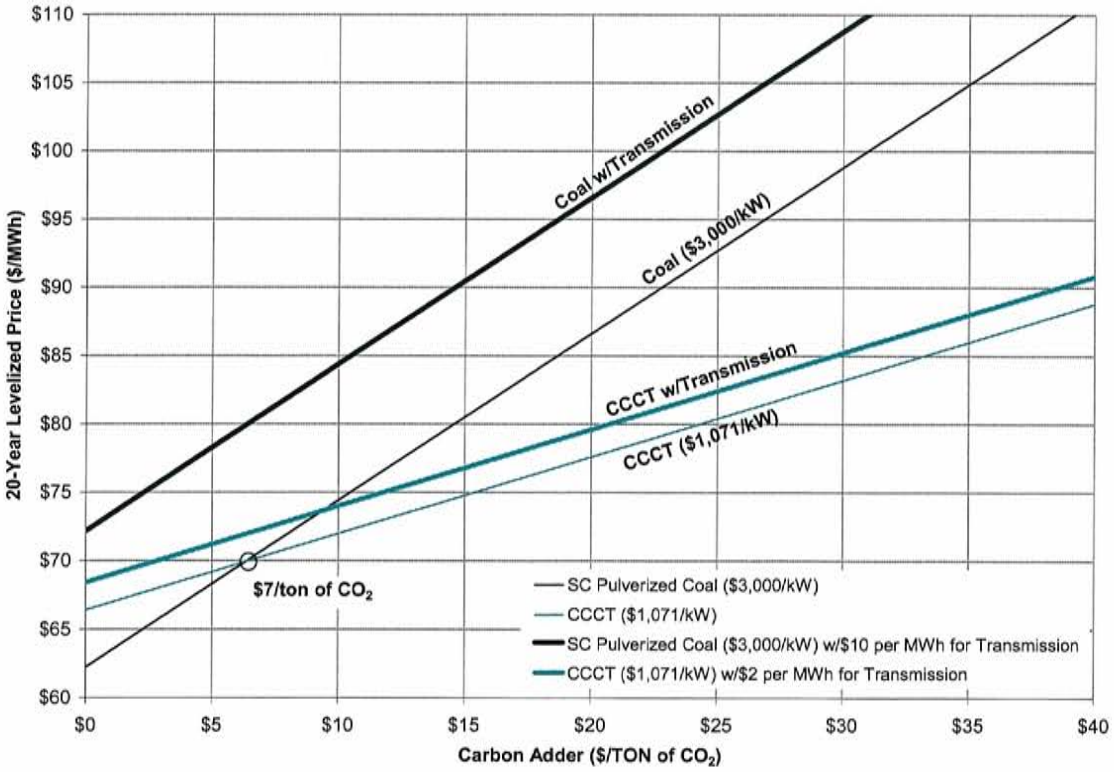
## Wyoming Pulverized Coal Resource

The 2006 IRP near-term action plan indicated that an initial commitment to the construction of a coal-fired resource would be necessary before the end of 2007 in order for a project to be on-line in 2013. Idaho Power began screening and evaluating coal-fired resources in 2006. The evaluation concluded in August 2007 and the results indicated construction costs had escalated substantially since resource cost estimates were prepared for the 2006 IRP.

Because the results of the screening and evaluation process were substantially different than the assumptions used in the 2006 IRP, Idaho Power re-evaluated the cost of a coal resource against a combined cycle combustion turbine (CCCT). In this updated analysis, a cost estimate of $1,071 per kW was used for the CCCT based on an estimate prepared by Idaho Power in mid-2007 and $3,000 per kW was used for the coal resource.

Figure 6 is a "tipping point" chart which shows the levelized price of energy for both a pulverized coal and a CCCT resource over a range of carbon adder costs. A carbon adder of $21 per ton of $CO_2$ is the "tipping point" where a CCCT resource becomes a better choice than pulverized coal.

**Figure 6. Levelized Price for Generating Resources vs. Carbon Adder**



In addition to comparing the resource costs, Figure 6 also shows an estimate for both resources accounting for the cost of transmission to deliver the energy to Idaho Power's main load center in southwestern Idaho. For this comparison, $10 per MWh was added to the cost of a pulverized coal facility located in Wyoming while $2 per MWh was used for a CCCT which could be built in southwestern Idaho. After accounting for the cost of transmission, Figure 6 shows the CCCT is the best choice for any level of assumed carbon adder.

In the fall of 2007, Idaho Power decided to no longer pursue the development of the 2013 coal-based resource. In addition to considering the cost of a coal-based resource, uncertainty surrounding the regulation of carbon emissions and the ability to permit a new coal resource were considered. Idaho Power continues to evaluate other coal-fired resource opportunities, including efficiency improvements at its jointly-owned facilities as well as monitoring the development of clean coal technologies.

## 2012 Baseload Resource RFP

In light of the decision to no longer pursue the development of a conventional coal resource in 2013, in April 2008 Idaho Power issued an RFP for 250 to 600 MW of dispatchable, physically delivered firm or unit contingent energy to be acquired under power purchase agreements or tolling agreements. The timing of the baseload addition was also accelerated to 2012 to account for the load demand from new large customers that were not included in the 2006 IRP load forecast. The range from 250 to 600 MW reflects the uncertainty regarding the actual demand of the new customers. Idaho Power expects to resolve the capacity issue in the next several months prior to completion of the RFP evaluation process.

## 2008 Combined Heat and Power RFP

A combined heat and power (CHP) project burns natural gas in a combustion turbine to generate electricity and then uses the exhaust heat from the turbine to generate steam for an industrial process. CHP projects typically result in a higher overall efficiency when compared to burning natural gas solely to create steam for an industrial process.

The 2006 IRP included 50 MW of CHP in 2010. Idaho Power is in the process of working with industrial customers to gauge the level of interest in new CHP projects. Major account representatives are using a specification sheet to guide their discussions with Idaho Power's industrial customers and depending on the level of interest, Idaho Power may issue an RFP later in 2008.

# 6. Transmission Resources

Idaho Power's transmission system is a key element serving the needs of Idaho Power's retail customers. Idaho Power relies on regional markets to supply a significant portion of energy and capacity. Idaho Power is especially dependent on the regional markets during peak periods. Reliance on regional markets has benefited Idaho Power customers during times of low prices because the costs of purchases, the revenue from surplus sales, and fuel expenses are shared with customers through the Power Cost Adjustment (PCA) mechanism. The following sections provide an update on transmission related activities since the 2006 IRP was published.

## Northern Tier Transmission Group

The Northern Tier Transmission Group (NTTG) was formed in early 2007 with an overall goal of improving the operation and expansion of the high-voltage transmission system that delivers power to consumers in seven western states. In addition to Idaho Power, other members include Deseret Power Electric Cooperative, NorthWestern Energy, Rocky Mountain Power/PacifiCorp and the Utah Associated Municipal Power Systems (UAMPS).

NTTG will address and coordinate regional transmission use and planning using working groups that are guided by a steering committee of transmission owner executives and state regulators. The working groups are designed around three primary objectives: 1) improving available transmission capacity, 2) expediting the planning for transmission grid expansion, and 3) collaborating on control area operations. For each of the three objectives, NTTG has encouraged participation and solicited input from stakeholders including transmission owners, customers, and state regulators. Through a coordinated and collaborative planning and implementation process, NTTG is working to maintain a robust transmission system that supports an efficient regional electricity market.

## Transmission Project Status

The 2006 IRP described five regional-scale transmission projects that were included in the resource planning process. The following projects were included in the 2006 IRP as the most viable transmission alternatives.

- McNary (Columbia River) to the Locust Substation (Boise) via Brownlee
- Lolo (Lewiston area) to Oxbow
- Bridger, Wyoming to the Boise Bench Substation via the Midpoint Substation
- Garrison or Townsend, Montana to the Boise Bench Substation via the Midpoint Substation
- White Pine, Nevada to the Boise Bench Substation via the Midpoint Substation

Since the completion of the 2006 IRP, Idaho Power has announced plans for construction of two regional-scale transmission projects. The Hemingway-Boardman project (McNary to Locust) extends from northeastern Oregon to the Boise area, and the Gateway West project (Bridger, Wyoming to Boise Bench) extends from central Wyoming to the Boise area. The Hemingway-Boardman and the Gateway West projects have both been identified as "fast track" projects by NTTG because both projects provide considerable benefits to the regional transmission system.

NTTG has also identified NorthWestern Energy's proposed 500-kV Mountain States Transmission Intertie (MSTI) between southwestern Montana and Idaho Power's

Borah or Midpoint substations as a beneficial project. The MSTI project is similar to the Garrison-Townsend alternative discussed in the 2006 IRP. NorthWestern Energy expects the MSTI line to be placed in service in 2013.

Expansion of other regional transmission resources includes PacifiCorp's plan for a 500-kV line between the Hemingway substation in Boise and the Bonneville Power Administration's Captain Jack substation in southern Oregon. PacifiCorp anticipates an in-service date of 2014 for the Hemingway to Captain Jack project. All of the transmission projects reflect a collaborative, regional-scale effort by NTTG to upgrade the region's transmission resources in the face of continuing population growth and the corresponding growth in the demand for electricity. The following sections provide additional details on the transmission projects Idaho Power is either currently working on or has completed since the 2006 IRP was published.

## Borah-West Upgrade

The 2006 IRP discussed ongoing construction to upgrade the existing Borah-West path. The transmission improvements to the Borah-West path were initially identified in the 2004 IRP and have been completed and were placed in service in June 2007. Completion of the upgrade has resulted in a 250 MW increase in the east-to-west transfer capacity of the Borah-West path which increases the path rating to 2,557 MW. As discussed in the 2006 IRP, the Borah-West improvements are critical to serve load growth in the Boise area from any new generation sited on the east side of Idaho Power's service area.

## Hemingway-Boardman Project

Consistent with Idaho Power's 2006 IRP and the requirements of other transmission customers, Idaho Power is exploring alternatives for the construction of a 500-kV line between southwestern Idaho and the Pacific Northwest. Several electric utilities, including Idaho Power, have proposed development of a transmission substation near Boardman, Oregon, which would serve as the northwest terminal of the project. The Idaho terminal would be the proposed Hemingway substation located south of Boise on the south side of the Snake River between the towns of Melba and Murphy. Idaho Power and a number of other utilities with proposed regional transmission projects in the Northwest have signed a letter agreeing to coordinate technical studies. The technical studies and other planning and project management activities have begun and the Hemingway-Boardman transmission line could be in service as early as 2012.

## Gateway West Project

Idaho Power and PacifiCorp are jointly exploring the Gateway West Project to build two 500-kV lines between the Jim Bridger plant in Wyoming and Boise. The lines would be designed to increase electrical transmission capacity across southern Idaho in response to increasing customer energy demand. The Gateway West project has been submitted to the Western Electricity Coordinating Council (WECC) for the initial phases of the ratings process. A review team has been established from members of the WECC to analyze the effects of the project on the existing transmission system. When the study is complete, necessary modifications will be made to the engineering design and the final rating will be obtained prior to the beginning of construction.

Planning and project management personnel from both Idaho Power and PacifiCorp have begun the initial work on the Gateway West project. Idaho Power expects that the majority of the project will be completed between 2012 and 2014, depending on the amount of time required for right-of-way acquisition, siting and permitting activities.

# 7. Resource Portfolio and Action Plan Update

Over the past 90 years, Idaho Power has developed a blended portfolio of generation resources. Idaho Power believes a portfolio of diverse generation resources is the most cost effective and lowest risk method to address the increasing energy demands of its customers.

New customer growth is the primary driver behind Idaho Power's need for the additional resources identified in the 2006 IRP. Population growth throughout southern Idaho and specifically, in the Treasure Valley, requires that Idaho Power acquire new resources to meet both the peak-hour and average energy needs of its customers.

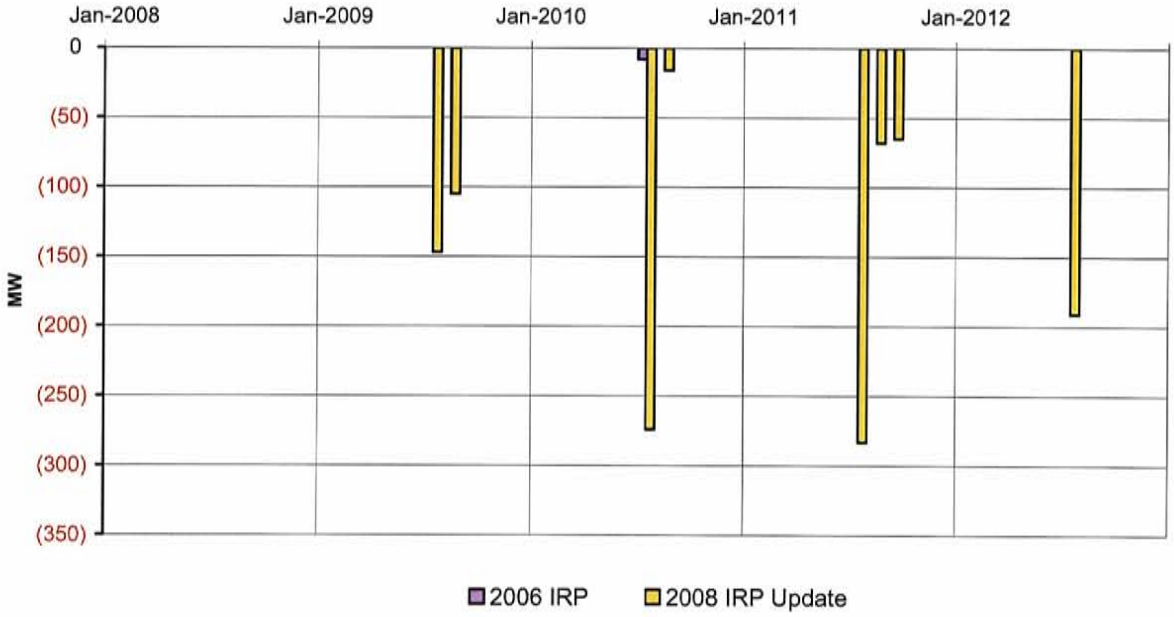
New supply-side generation resources, demand-side programs and increasing the transmission capacity to the Pacific Northwest are the likely alternatives Idaho Power will use to meet the increasing energy demands of its customers. Idaho Power's customers have expressed a desire for a balanced resource portfolio containing resources that are financially, environmentally, and socially responsible. Renewable energy and demand-side programs are significant components of the resource portfolio selected in the 2006 IRP and will continue to be part of Idaho Power's balanced approach to resource planning.

## Peak-Hour Load

Peak-hour load deficiencies are determined using 90th percentile water and 95th percentile peak-hour load conditions, coupled with Idaho Power's ability to import additional energy on its transmission system to reduce any deficits. In addition to these criteria, 70th percentile average load conditions are assumed, but the hydrologic, peak-hour load and transmission constraint criteria are the major factors in determining the peak-hour load deficiencies. Peak-hour load planning criteria are more stringent than average load criteria because Idaho Power's ability to import additional energy is typically limited during peak-hour load periods.

Figure 7 shows the updated monthly peak-hour load deficiencies compared to those presented in the 2006 IRP, which accounted for the addition

**Figure 7. 2008–2012 Peak-Hour Deficits**



of resources in the preferred portfolio. The differences are the result of the updated sales and load forecast, DSM program performance, adjustments to the hydro generation forecast, the current level of PURPA development, and changes in the timing and capacity of other resources identified in the 2006 IRP. The deficiencies shown in Figure 7 show the new baseload resource is needed prior to 2012. However, the 2012 Baseload Resource RFP specifies a beginning delivery date of April 2012 based on the estimated time required to build a new resource.

## Action Plan Update and Portfolio Comparison

The near-term action plan presented in the 2006 IRP proposed a schedule of events associated with implementing the preferred resource portfolio. Resource action plans are expected to be flexible to accommodate the uncertainty associated with acquiring resources through an RFP process, and the uncertainty associated with developing resources in cooperation with other utilities. Idaho Power has deviated from the action plan, as necessary, to achieve the goal of acquiring sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area while continuing to balance cost, risk, reliability, and environmental concerns. An updated near-term action plan is presented in Table 9 and a comparison of the preferred portfolio from the 2006 IRP and the updated portfolio is shown in Table 10.

**Table 9. Updated Near-Term Action Plan through 2010**

| Activity | |
|---|---|
| ***2008*** | ***2009*** |
| 1. January - Issue RFP for 50-100 MW of geothermal energy. | 1. Conclude the 2012 Baseload Resource RFP process. |
| 2. March – 170 MW Danskin expansion on-line. | 2. Continue DSM implementation plans with guidance from the EEAG. |
| 3. March – Prepare and submit the 2007 Demand-Side Management Annual Report. | 3. Continue working with industrial customers on CHP development opportunities. |
| 4. April - Solicit expressions of interest from industrial customers for CHP development. | 4. Complete the 2009 IRP and submit to the Idaho and Oregon Commissions in June 2009. |
| 5. April - Issue 2012 Baseload Resource RFP. | 5. Make final commitments on 225 MW Hemmingway-Boardman Transmission Project. |
| 6. June – Submit 2008 IRP Update to the Idaho and Oregon Commissions. | 6. Make final commitments on 500 kV Gateway West Transmission Project. |
| 7. July – Begin the 2009 IRP process with the IRP Advisory Council. | 7. Activities associated with the 2012 Baseload Resource RFP depending on the outcome of the RFP process. |
| 8. September – Announce successful bidder(s) in the geothermal RFP process. | ***2010*** |
| 9. October – Bids due for the 2012 Baseload Resource RFP. | 1. Continue DSM implementation plans with guidance from the EEAG. |
| | 2. Issue RFP for wind generation depending on current level of PURPA wind development. |

**Table 10. 2006 IRP Preferred Portfolio and Updated Portfolio**

| 2006 IRP Preferred Portfolio | | | Updated Portfolio | | |
|---|---|---|---|---|---|
| **Year** | **Resource** | **MW** | **Year** | **Resource** | **MW** |
| 2008 | Wind (2005 RFP) | 100 | 2008 | Wind (2005 RFP)[1] | 100 |
| 2009 | Geothermal (2006 RFP) | 50 | 2009 | Geothermal (2006 RFP)[2] | 50 |
| 2010 | CHP | 50 | 2010 | CHP (2008 Solicitation)[3] | 50 |
| | | | 2011 | Geothermal (2008 RFP)[4] | 50 |
| 2012 | Wind | 150 | 2012 | Wind[5] | 150 |
| 2012 | Transmission McNary–Boise | 225 | 2012 | Trans. Hemmingway-Boardman[6] | 225 |
| | | | 2012 | Southwest Idaho CCCT[7] | 250 |
| 2013 | Wyoming Pulverized Coal[7] | 250 | | | |
| 2017 | Regional IGCC Coal | 250 | 2017 | Regional IGCC Coal | 250 |
| 2019 | Transmission Lolo–IPC | 60 | 2019 | Transmission Lolo–IPC | 60 |
| 2020 | CHP | 100 | 2020 | CHP | 100 |
| 2021 | Geothermal | 50 | 2021 | Geothermal | 50 |
| 2022 | Geothermal | 50 | 2022 | Geothermal | 50 |
| 2023 | INL Nuclear | 250 | 2023 | INL Nuclear | 250 |
| | **Total Nameplate** | **1,585** | | **Total Nameplate** | **1,635** |

1 Horizon Wind Energy Contract (100.65 MW) - Elkhorn Valley Wind Project (on-line December 2007).

2 U.S. Geothermal Contract (45.5 MW) - Raft River #1 (13 MW on-line October 2007), Raft River #3 (6.5 MW) and Neal Hot Springs #1 (13 MW) and #2 (13 MW) are under development.

3 In April 2008, Idaho Power began soliciting industrial customers within its service area for expressions of interest in the development of combined heat and power projects at existing industrial facilities. Depending on the level of interest, a formal RFP may be issued in late 2008.

4 An RFP for 50 to 100 MW of geothermal energy was released in January 2008 to offset deficits resulting from PURPA contract terminations.

5 Actual quantity will depend on level of PURPA wind development.

6 Project was renamed once actual termination points were identified.

7 Due to escalating construction costs and continued uncertainty surrounding future GHG laws and regulations, Idaho Power has shifted its focus from a conventional coal-fired resource to the development of a combined-cycle, natural gas resource located closer to its load center in southern Idaho.

# 8. SUMMARY

The Idaho PUC and the Oregon PUC both asked Idaho Power to file an IRP update and the company believes the 2008 Integrated Resource Plan Update meets the requirements of Idaho Order 303017 and Oregon Order 07-002 by addressing the following:

- Describe the actions that Idaho Power has taken to implement the 2006 IRP.
- Provide an assessment of what has changed since the 2006 IRP was filed in the fall of 2006. In the 2008 IRP Update, Idaho Power has discussed various resource issues including load, resource contracts, supply-side resource additions and plans, demand-side program implementation and performance, and transmission resource projects and plans.
- Explain deviations and changes that have occurred since the 2006 IRP was filed in 2006.

One of the key strengths of Idaho Power's planning process is that the IRP is updated on a regular basis. Frequent planning and review allows Idaho Power, the Idaho and Oregon utility commissions, and concerned customers, including the IRP Advisory Council, to revisit the resource plan and make periodic adjustments and corrections to reflect changes in technology, economic conditions, and regulatory requirements. During the period between resource plan filings, the public and regulatory oversight of the activities identified in the near-term action plan allows for discussion and adjustment of the IRP as warranted.

## 2009 Integrated Resource Plan

Initial work on Idaho Power's 2009 IRP has already begun and many of the issues outlined in this update will form the foundation for the 2009 IRP. Idaho Power is planning to hold the first 2009 IRP Advisory Council meeting in mid-year 2008. The first meeting will be an educational session which will be followed by regular monthly meetings starting in the fall and continuing through the winter. Idaho Power anticipates having a draft version of the 2009 IRP available in the spring and expects to file the resource plan with the Idaho and Oregon utility commissions in June 2009.

## Coordination with Other Idaho Electric Utilities

In April 2007, Idaho Power requested a one-year delay in the filing of its next IRP until June 2009 to coordinate the filing with Avista and PacifiCorp's Integrated Resource Plans. The Idaho PUC accepted the one-year IRP filing delay in Order 30317 issued on May 23, 2007.

The adjusted filing schedule will provide an opportunity for Idaho Power, Avista and PacifiCorp to explore possibilities for the joint development of supply-side resources and transmission projects. Idaho Power plans to participate in Avista and PacifiCorp's resource planning process and will invite representatives from each utility to attend Idaho Power's IRP Advisory Council meetings.

# Appendix A

# Sales and Load Forecast Data

**Expected Case Average Forecast Annual Growth Rates (%)**

| | 2008–2013 | 2008–2018 | 2008–2027 |
|---|---|---|---|
| **Sales** | | | |
| Residential Sales | 1.5 | 1.2 | 1.4 |
| Commercial Sales | 1.9 | 1.5 | 1.8 |
| Irrigation Sales | -0.2 | -0.1 | 0.0 |
| Industrial Sales | 1.9 | 1.7 | 1.8 |
| Additional Firm Sales | 4.7 | 2.2 | 1.0 |
| Firm Sales | 1.7 | 1.3 | 1.4 |
| System Sales | 1.7 | 1.3 | 1.4 |
| Total Sales | 1.7 | 1.3 | 1.4 |
| **Loads** | | | |
| Residential Load | 1.4 | 1.2 | 1.4 |
| Commercial Load | 1.9 | 1.5 | 1.8 |
| Irrigation Load | -0.1 | -0.1 | 0.0 |
| Industrial Load | 2.0 | 1.7 | 1.8 |
| Additional Firm Sales | 4.7 | 2.2 | 1.0 |
| Firm Load Losses | 1.7 | 1.3 | 1.5 |
| Firm Load | 1.7 | 1.3 | 1.5 |
| System Load | 1.7 | 1.3 | 1.5 |
| Total Load | 1.7 | 1.3 | 1.5 |
| Firm Requirement Load | 1.7 | 1.3 | 1.5 |
| **Peaks** | | | |
| Firm Peak | 1.9 | 1.7 | 1.8 |
| System Peak | 1.9 | 1.7 | 1.8 |
| Total Peak | 1.9 | 1.7 | 1.8 |
| Firm Requirement Peak | 1.9 | 1.7 | 1.8 |
| Winter Peak | 1.5 | 0.6 | 1.3 |
| Summer Peak | 1.9 | 1.7 | 1.8 |
| **Customers** | | | |
| Residential Customers | 2.3 | 2.2 | 2.2 |
| Commercial Customers | 2.5 | 2.4 | 2.3 |
| Irrigation Customers | 1.6 | 1.5 | 1.4 |
| Industrial Customers | 1.4 | 1.4 | 1.3 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2008 | Feb. 2008 | Mar. 2008 | Apr. 2008 | May. 2008 | Jun. 2008 | Jul. 2008 | Aug. 2008 | Sep. 2008 | Oct. 2008 | Nov. 2008 | Dec. 2008 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 805 | 720 | 620 | 486 | 454 | 508 | 594 | 597 | 489 | 504 | 640 | 820 |
| Commercial | 485 | 465 | 442 | 390 | 409 | 459 | 494 | 498 | 445 | 435 | 454 | 496 |
| Irrigation | 0 | 0 | 4 | 76 | 238 | 482 | 573 | 457 | 283 | 68 | 2 | 2 |
| Industrial | 276 | 266 | 266 | 260 | 266 | 283 | 277 | 281 | 279 | 284 | 280 | 279 |
| Additional Firm | 140 | 137 | 135 | 133 | 132 | 122 | 133 | 131 | 128 | 131 | 135 | 140 |
| Loss | 151 | 140 | 128 | 152 | 172 | 185 | 208 | 196 | 159 | 136 | 146 | 170 |
| Firm Load | 1,857 | 1,729 | 1,596 | 1,497 | 1,671 | 2,038 | 2,279 | 2,160 | 1,783 | 1,558 | 1,657 | 1,906 |
| Light Load | 1,717 | 1,612 | 1,476 | 1,349 | 1,500 | 1,843 | 2,043 | 1,934 | 1,592 | 1,395 | 1,539 | 1,769 |
| Heavy Load | 1,967 | 1,816 | 1,690 | 1,606 | 1,806 | 2,195 | 2,466 | 2,339 | 1,936 | 1,675 | 1,759 | 2,014 |
| System Load | 1,857 | 1,729 | 1,596 | 1,497 | 1,671 | 2,038 | 2,279 | 2,160 | 1,783 | 1,558 | 1,657 | 1,906 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,857 | 1,729 | 1,596 | 1,497 | 1,671 | 2,038 | 2,279 | 2,160 | 1,783 | 1,558 | 1,657 | 1,906 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2008 | Feb. 2008 | Mar. 2008 | Apr. 2008 | May. 2008 | Jun. 2008 | Jul. 2008 | Aug. 2008 | Sep. 2008 | Oct. 2008 | Nov. 2008 | Dec. 2008 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -12 | -12 | -11 | -12 | -18 | -25 | -30 | -28 | -22 | -15 | -12 | -12 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -66 | -66 | -62 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,542 | 2,411 | 2,288 | 1,970 | 2,733 | 3,194 | 3,240 | 2,986 | 2,703 | 2,038 | 2,347 | 2,781 |
| System Peak (1 Hour) | 2,542 | 2,411 | 2,288 | 1,970 | 2,733 | 3,194 | 3,240 | 2,986 | 2,703 | 2,038 | 2,347 | 2,781 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,542 | 2,411 | 2,288 | 1,970 | 2,733 | 3,194 | 3,240 | 2,986 | 2,703 | 2,038 | 2,347 | 2,781 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2009 | Feb. 2009 | Mar. 2009 | Apr. 2009 | May. 2009 | Jun. 2009 | Jul. 2009 | Aug. 2009 | Sep. 2009 | Oct. 2009 | Nov. 2009 | Dec. 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 820 | 732 | 631 | 494 | 461 | 519 | 609 | 612 | 500 | 516 | 654 | 835 |
| Commercial | 494 | 474 | 451 | 398 | 418 | 469 | 506 | 509 | 454 | 444 | 462 | 505 |
| Irrigation | 0 | 0 | 4 | 76 | 237 | 481 | 572 | 456 | 282 | 67 | 2 | 2 |
| Industrial | 282 | 273 | 273 | 267 | 272 | 290 | 284 | 288 | 286 | 291 | 286 | 285 |
| Additional Firm | 155 | 166 | 164 | 163 | 165 | 158 | 173 | 173 | 169 | 172 | 176 | 182 |
| Loss | 154 | 144 | 132 | 156 | 177 | 189 | 213 | 202 | 164 | 141 | 151 | 175 |
| Firm Load | 1,906 | 1,789 | 1,654 | 1,554 | 1,731 | 2,107 | 2,357 | 2,240 | 1,856 | 1,630 | 1,732 | 1,985 |
| Light Load | 1,762 | 1,668 | 1,530 | 1,400 | 1,554 | 1,905 | 2,112 | 2,006 | 1,657 | 1,460 | 1,609 | 1,842 |
| Heavy Load | 2,020 | 1,880 | 1,751 | 1,666 | 1,883 | 2,255 | 2,550 | 2,425 | 2,015 | 1,753 | 1,840 | 2,097 |
| System Load | 1,906 | 1,789 | 1,654 | 1,554 | 1,731 | 2,107 | 2,357 | 2,240 | 1,856 | 1,630 | 1,732 | 1,985 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,906 | 1,789 | 1,654 | 1,554 | 1,731 | 2,107 | 2,357 | 2,240 | 1,856 | 1,630 | 1,732 | 1,985 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2009 | Feb. 2009 | Mar. 2009 | Apr. 2009 | May. 2009 | Jun. 2009 | Jul. 2009 | Aug. 2009 | Sep. 2009 | Oct. 2009 | Nov. 2009 | Dec. 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -19 | -18 | -18 | -18 | -27 | -38 | -46 | -43 | -33 | -22 | -19 | -18 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -77 | -78 | -73 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,583 | 2,464 | 2,339 | 2,006 | 2,817 | 3,281 | 3,338 | 3,075 | 2,792 | 2,110 | 2,423 | 2,867 |
| System Peak (1 Hour) | 2,583 | 2,464 | 2,339 | 2,006 | 2,817 | 3,281 | 3,338 | 3,075 | 2,792 | 2,110 | 2,423 | 2,867 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,583 | 2,464 | 2,339 | 2,006 | 2,817 | 3,281 | 3,338 | 3,075 | 2,792 | 2,110 | 2,423 | 2,867 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2010 | Feb. 2010 | Mar. 2010 | Apr. 2010 | May. 2010 | Jun. 2010 | Jul. 2010 | Aug. 2010 | Sep. 2010 | Oct. 2010 | Nov. 2010 | Dec. 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 832 | 741 | 639 | 499 | 467 | 528 | 621 | 625 | 509 | 525 | 665 | 849 |
| Commercial | 504 | 484 | 461 | 407 | 428 | 481 | 518 | 521 | 465 | 454 | 472 | 515 |
| Irrigation | 0 | 0 | 4 | 77 | 237 | 480 | 572 | 456 | 282 | 67 | 2 | 2 |
| Industrial | 288 | 279 | 279 | 272 | 278 | 297 | 290 | 295 | 292 | 297 | 293 | 292 |
| Additional Firm | 179 | 178 | 174 | 171 | 171 | 162 | 173 | 171 | 167 | 170 | 174 | 179 |
| Loss | 158 | 147 | 135 | 159 | 180 | 193 | 217 | 205 | 166 | 143 | 153 | 178 |
| Firm Load | 1,961 | 1,829 | 1,691 | 1,585 | 1,760 | 2,140 | 2,392 | 2,273 | 1,882 | 1,656 | 1,759 | 2,015 |
| Light Load | 1,813 | 1,705 | 1,564 | 1,428 | 1,580 | 1,935 | 2,144 | 2,035 | 1,680 | 1,483 | 1,634 | 1,870 |
| Heavy Load | 2,088 | 1,922 | 1,782 | 1,699 | 1,915 | 2,290 | 2,571 | 2,460 | 2,043 | 1,792 | 1,859 | 2,129 |
| System Load | 1,961 | 1,829 | 1,691 | 1,585 | 1,760 | 2,140 | 2,392 | 2,273 | 1,882 | 1,656 | 1,759 | 2,015 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,961 | 1,829 | 1,691 | 1,585 | 1,760 | 2,140 | 2,392 | 2,273 | 1,882 | 1,656 | 1,759 | 2,015 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2010 | Feb. 2010 | Mar. 2010 | Apr. 2010 | May. 2010 | Jun. 2010 | Jul. 2010 | Aug. 2010 | Sep. 2010 | Oct. 2010 | Nov. 2010 | Dec. 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -25 | -24 | -24 | -24 | -35 | -50 | -61 | -58 | -44 | -30 | -25 | -25 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,640 | 2,499 | 2,379 | 2,030 | 2,874 | 3,346 | 3,400 | 3,140 | 2,834 | 2,133 | 2,453 | 2,941 |
| System Peak (1 Hour) | 2,640 | 2,499 | 2,379 | 2,030 | 2,874 | 3,346 | 3,400 | 3,140 | 2,834 | 2,133 | 2,453 | 2,941 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,640 | 2,499 | 2,379 | 2,030 | 2,874 | 3,346 | 3,400 | 3,140 | 2,834 | 2,133 | 2,453 | 2,941 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2011 | Feb. 2011 | Mar. 2011 | Apr. 2011 | May. 2011 | Jun. 2011 | Jul. 2011 | Aug. 2011 | Sep. 2011 | Oct. 2011 | Nov. 2011 | Dec. 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 844 | 751 | 647 | 505 | 473 | 539 | 635 | 639 | 519 | 534 | 677 | 859 |
| Commercial | 513 | 493 | 470 | 415 | 436 | 492 | 529 | 532 | 475 | 463 | 481 | 523 |
| Irrigation | 0 | 0 | 4 | 77 | 236 | 479 | 571 | 455 | 282 | 66 | 2 | 2 |
| Industrial | 294 | 284 | 284 | 278 | 283 | 302 | 296 | 300 | 298 | 303 | 298 | 297 |
| Additional Firm | 181 | 181 | 176 | 174 | 173 | 164 | 175 | 173 | 169 | 165 | 168 | 173 |
| Loss | 161 | 149 | 137 | 161 | 183 | 195 | 221 | 209 | 169 | 146 | 156 | 180 |
| Firm Load | 1,993 | 1,858 | 1,718 | 1,609 | 1,785 | 2,170 | 2,427 | 2,308 | 1,911 | 1,678 | 1,782 | 2,035 |
| Light Load | 1,843 | 1,733 | 1,590 | 1,450 | 1,602 | 1,962 | 2,175 | 2,066 | 1,706 | 1,503 | 1,656 | 1,889 |
| Heavy Load | 2,123 | 1,952 | 1,811 | 1,725 | 1,942 | 2,322 | 2,644 | 2,482 | 2,075 | 1,816 | 1,883 | 2,141 |
| System Load | 1,993 | 1,858 | 1,718 | 1,609 | 1,785 | 2,170 | 2,427 | 2,308 | 1,911 | 1,678 | 1,782 | 2,035 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,993 | 1,858 | 1,718 | 1,609 | 1,785 | 2,170 | 2,427 | 2,308 | 1,911 | 1,678 | 1,782 | 2,035 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2011 | Feb. 2011 | Mar. 2011 | Apr. 2011 | May. 2011 | Jun. 2011 | Jul. 2011 | Aug. 2011 | Sep. 2011 | Oct. 2011 | Nov. 2011 | Dec. 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -32 | -31 | -30 | -30 | -44 | -62 | -76 | -73 | -56 | -37 | -32 | -31 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,682 | 2,528 | 2,424 | 2,062 | 2,924 | 3,404 | 3,464 | 3,192 | 2,880 | 2,152 | 2,472 | 2,956 |
| System Peak (1 Hour) | 2,682 | 2,528 | 2,424 | 2,062 | 2,924 | 3,404 | 3,464 | 3,192 | 2,880 | 2,152 | 2,472 | 2,956 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,682 | 2,528 | 2,424 | 2,062 | 2,924 | 3,404 | 3,464 | 3,192 | 2,880 | 2,152 | 2,472 | 2,956 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2012 | Feb. 2012 | Mar. 2012 | Apr. 2012 | May. 2012 | Jun. 2012 | Jul. 2012 | Aug. 2012 | Sep. 2012 | Oct. 2012 | Nov. 2012 | Dec. 2012 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 850 | 755 | 651 | 508 | 476 | 545 | 645 | 649 | 524 | 540 | 684 | 867 |
| Commercial | 520 | 500 | 477 | 421 | 443 | 501 | 538 | 540 | 482 | 471 | 488 | 531 |
| Irrigation | 0 | 0 | 4 | 77 | 236 | 477 | 570 | 454 | 281 | 66 | 2 | 2 |
| Industrial | 298 | 288 | 288 | 281 | 287 | 306 | 300 | 305 | 302 | 307 | 302 | 301 |
| Additional Firm | 172 | 170 | 169 | 167 | 167 | 157 | 169 | 166 | 163 | 165 | 168 | 173 |
| Loss | 162 | 150 | 138 | 162 | 184 | 197 | 223 | 211 | 171 | 148 | 157 | 182 |
| Firm Load | 2,002 | 1,863 | 1,727 | 1,615 | 1,792 | 2,184 | 2,445 | 2,325 | 1,923 | 1,697 | 1,802 | 2,057 |
| Light Load | 1,851 | 1,737 | 1,597 | 1,455 | 1,609 | 1,975 | 2,191 | 2,082 | 1,717 | 1,520 | 1,674 | 1,909 |
| Heavy Load | 2,121 | 1,957 | 1,820 | 1,743 | 1,937 | 2,337 | 2,663 | 2,500 | 2,104 | 1,824 | 1,904 | 2,184 |
| System Load | 2,002 | 1,863 | 1,727 | 1,615 | 1,792 | 2,184 | 2,445 | 2,325 | 1,923 | 1,697 | 1,802 | 2,057 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,002 | 1,863 | 1,727 | 1,615 | 1,792 | 2,184 | 2,445 | 2,325 | 1,923 | 1,697 | 1,802 | 2,057 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2012 | Feb. 2012 | Mar. 2012 | Apr. 2012 | May. 2012 | Jun. 2012 | Jul. 2012 | Aug. 2012 | Sep. 2012 | Oct. 2012 | Nov. 2012 | Dec. 2012 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -38 | -37 | -37 | -37 | -54 | -74 | -92 | -89 | -68 | -45 | -39 | -38 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,687 | 2,523 | 2,426 | 2,058 | 2,963 | 3,446 | 3,510 | 3,224 | 2,917 | 2,169 | 2,493 | 2,965 |
| System Peak (1 Hour) | 2,687 | 2,523 | 2,426 | 2,058 | 2,963 | 3,446 | 3,510 | 3,224 | 2,917 | 2,169 | 2,493 | 2,965 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,687 | 2,523 | 2,426 | 2,058 | 2,963 | 3,446 | 3,510 | 3,224 | 2,917 | 2,169 | 2,493 | 2,965 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2013 | Feb. 2013 | Mar. 2013 | Apr. 2013 | May. 2013 | Jun. 2013 | Jul. 2013 | Aug. 2013 | Sep. 2013 | Oct. 2013 | Nov. 2013 | Dec. 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 856 | 760 | 655 | 510 | 479 | 551 | 656 | 659 | 531 | 547 | 691 | 874 |
| Commercial | 527 | 507 | 485 | 427 | 450 | 510 | 547 | 549 | 490 | 478 | 495 | 537 |
| Irrigation | 0 | 0 | 4 | 77 | 235 | 477 | 569 | 454 | 281 | 65 | 2 | 2 |
| Industrial | 303 | 293 | 294 | 287 | 293 | 313 | 306 | 311 | 308 | 313 | 308 | 307 |
| Additional Firm | 172 | 172 | 169 | 167 | 167 | 157 | 169 | 166 | 163 | 165 | 168 | 173 |
| Loss | 164 | 152 | 140 | 164 | 186 | 200 | 226 | 214 | 173 | 150 | 160 | 184 |
| Firm Load | 2,023 | 1,884 | 1,746 | 1,631 | 1,810 | 2,208 | 2,472 | 2,352 | 1,946 | 1,718 | 1,824 | 2,078 |
| Light Load | 1,870 | 1,757 | 1,615 | 1,470 | 1,625 | 1,996 | 2,215 | 2,106 | 1,737 | 1,539 | 1,695 | 1,928 |
| Heavy Load | 2,144 | 1,980 | 1,848 | 1,749 | 1,956 | 2,377 | 2,674 | 2,530 | 2,128 | 1,848 | 1,927 | 2,206 |
| System Load | 2,023 | 1,884 | 1,746 | 1,631 | 1,810 | 2,208 | 2,472 | 2,352 | 1,946 | 1,718 | 1,824 | 2,078 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,023 | 1,884 | 1,746 | 1,631 | 1,810 | 2,208 | 2,472 | 2,352 | 1,946 | 1,718 | 1,824 | 2,078 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2013 | Feb. 2013 | Mar. 2013 | Apr. 2013 | May. 2013 | Jun. 2013 | Jul. 2013 | Aug. 2013 | Sep. 2013 | Oct. 2013 | Nov. 2013 | Dec. 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -45 | -44 | -43 | -43 | -63 | -87 | -107 | -104 | -79 | -53 | -45 | -44 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,703 | 2,536 | 2,439 | 2,060 | 3,010 | 3,502 | 3,567 | 3,276 | 2,960 | 2,189 | 2,516 | 2,995 |
| System Peak (1 Hour) | 2,703 | 2,536 | 2,439 | 2,060 | 3,010 | 3,502 | 3,567 | 3,276 | 2,960 | 2,189 | 2,516 | 2,995 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,703 | 2,536 | 2,439 | 2,060 | 3,010 | 3,502 | 3,567 | 3,276 | 2,960 | 2,189 | 2,516 | 2,995 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2014 | Feb. 2014 | Mar. 2014 | Apr. 2014 | May. 2014 | Jun. 2014 | Jul. 2014 | Aug. 2014 | Sep. 2014 | Oct. 2014 | Nov. 2014 | Dec. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 860 | 761 | 657 | 511 | 480 | 556 | 664 | 667 | 536 | 551 | 695 | 879 |
| Commercial | 532 | 512 | 490 | 432 | 456 | 517 | 554 | 555 | 496 | 484 | 500 | 542 |
| Irrigation | 0 | 0 | 4 | 76 | 234 | 474 | 566 | 452 | 279 | 65 | 2 | 2 |
| Industrial | 307 | 297 | 297 | 290 | 297 | 317 | 309 | 315 | 312 | 317 | 312 | 311 |
| Additional Firm | 172 | 172 | 168 | 166 | 166 | 157 | 169 | 166 | 163 | 165 | 168 | 173 |
| Loss | 165 | 152 | 141 | 165 | 187 | 201 | 228 | 216 | 175 | 151 | 161 | 186 |
| Firm Load | 2,036 | 1,895 | 1,757 | 1,640 | 1,820 | 2,222 | 2,490 | 2,371 | 1,960 | 1,733 | 1,838 | 2,092 |
| Light Load | 1,882 | 1,767 | 1,626 | 1,478 | 1,633 | 2,009 | 2,231 | 2,123 | 1,750 | 1,552 | 1,708 | 1,942 |
| Heavy Load | 2,157 | 1,991 | 1,861 | 1,759 | 1,966 | 2,393 | 2,693 | 2,567 | 2,128 | 1,863 | 1,953 | 2,211 |
| System Load | 2,036 | 1,895 | 1,757 | 1,640 | 1,820 | 2,222 | 2,490 | 2,371 | 1,960 | 1,733 | 1,838 | 2,092 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,036 | 1,895 | 1,757 | 1,640 | 1,820 | 2,222 | 2,490 | 2,371 | 1,960 | 1,733 | 1,838 | 2,092 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2014 | Feb. 2014 | Mar. 2014 | Apr. 2014 | May. 2014 | Jun. 2014 | Jul. 2014 | Aug. 2014 | Sep. 2014 | Oct. 2014 | Nov. 2014 | Dec. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -52 | -51 | -49 | -50 | -71 | -98 | -123 | -118 | -91 | -60 | -52 | -51 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,717 | 2,543 | 2,452 | 2,067 | 3,054 | 3,532 | 3,615 | 3,283 | 3,004 | 2,202 | 2,531 | 2,924 |
| System Peak (1 Hour) | 2,717 | 2,543 | 2,452 | 2,067 | 3,054 | 3,532 | 3,615 | 3,283 | 3,004 | 2,202 | 2,531 | 2,924 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,717 | 2,543 | 2,452 | 2,067 | 3,054 | 3,532 | 3,615 | 3,283 | 3,004 | 2,202 | 2,531 | 2,924 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2015 | Feb. 2015 | Mar. 2015 | Apr. 2015 | May. 2015 | Jun. 2015 | Jul. 2015 | Aug. 2015 | Sep. 2015 | Oct. 2015 | Nov. 2015 | Dec. 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 863 | 763 | 659 | 511 | 481 | 562 | 673 | 676 | 541 | 555 | 701 | 890 |
| Commercial | 537 | 517 | 495 | 436 | 461 | 524 | 561 | 562 | 502 | 490 | 505 | 549 |
| Irrigation | 0 | 0 | 4 | 77 | 234 | 475 | 567 | 452 | 280 | 65 | 2 | 2 |
| Industrial | 313 | 302 | 303 | 295 | 302 | 322 | 315 | 321 | 317 | 323 | 318 | 317 |
| Additional Firm | 172 | 172 | 168 | 166 | 166 | 157 | 169 | 166 | 163 | 165 | 168 | 173 |
| Loss | 166 | 153 | 142 | 166 | 189 | 203 | 230 | 218 | 176 | 153 | 162 | 188 |
| Firm Load | 2,051 | 1,908 | 1,770 | 1,652 | 1,834 | 2,243 | 2,515 | 2,396 | 1,979 | 1,750 | 1,856 | 2,119 |
| Light Load | 1,896 | 1,779 | 1,638 | 1,489 | 1,646 | 2,028 | 2,254 | 2,145 | 1,767 | 1,568 | 1,724 | 1,966 |
| Heavy Load | 2,173 | 2,004 | 1,875 | 1,772 | 1,995 | 2,400 | 2,721 | 2,594 | 2,149 | 1,882 | 1,971 | 2,239 |
| System Load | 2,051 | 1,908 | 1,770 | 1,652 | 1,834 | 2,243 | 2,515 | 2,396 | 1,979 | 1,750 | 1,856 | 2,119 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,051 | 1,908 | 1,770 | 1,652 | 1,834 | 2,243 | 2,515 | 2,396 | 1,979 | 1,750 | 1,856 | 2,119 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2015 | Feb. 2015 | Mar. 2015 | Apr. 2015 | May. 2015 | Jun. 2015 | Jul. 2015 | Aug. 2015 | Sep. 2015 | Oct. 2015 | Nov. 2015 | Dec. 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -58 | -57 | -55 | -56 | -78 | -108 | -135 | -130 | -100 | -66 | -58 | -57 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,709 | 2,536 | 2,426 | 2,035 | 3,102 | 3,590 | 3,671 | 3,339 | 3,049 | 2,219 | 2,549 | 2,974 |
| System Peak (1 Hour) | 2,709 | 2,536 | 2,426 | 2,035 | 3,102 | 3,590 | 3,671 | 3,339 | 3,049 | 2,219 | 2,549 | 2,974 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,709 | 2,536 | 2,426 | 2,035 | 3,102 | 3,590 | 3,671 | 3,339 | 3,049 | 2,219 | 2,549 | 2,974 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2016 | Feb. 2016 | Mar. 2016 | Apr. 2016 | May. 2016 | Jun. 2016 | Jul. 2016 | Aug. 2016 | Sep. 2016 | Oct. 2016 | Nov. 2016 | Dec. 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 875 | 772 | 667 | 517 | 488 | 574 | 689 | 693 | 552 | 566 | 712 | 899 |
| Commercial | 547 | 526 | 505 | 445 | 471 | 535 | 574 | 574 | 512 | 500 | 515 | 556 |
| Irrigation | 0 | 0 | 4 | 77 | 234 | 476 | 569 | 453 | 280 | 65 | 2 | 2 |
| Industrial | 317 | 307 | 307 | 300 | 307 | 327 | 320 | 326 | 322 | 328 | 322 | 322 |
| Additional Firm | 172 | 170 | 168 | 166 | 166 | 157 | 169 | 166 | 163 | 165 | 168 | 173 |
| Loss | 168 | 155 | 144 | 169 | 192 | 206 | 234 | 222 | 179 | 155 | 165 | 190 |
| Firm Load | 2,080 | 1,931 | 1,795 | 1,673 | 1,858 | 2,275 | 2,554 | 2,434 | 2,009 | 1,779 | 1,884 | 2,142 |
| Light Load | 1,922 | 1,801 | 1,661 | 1,508 | 1,668 | 2,057 | 2,289 | 2,180 | 1,794 | 1,593 | 1,751 | 1,988 |
| Heavy Load | 2,215 | 2,028 | 1,892 | 1,794 | 2,021 | 2,434 | 2,782 | 2,618 | 2,181 | 1,925 | 1,991 | 2,253 |
| System Load | 2,080 | 1,931 | 1,795 | 1,673 | 1,858 | 2,275 | 2,554 | 2,434 | 2,009 | 1,779 | 1,884 | 2,142 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,080 | 1,931 | 1,795 | 1,673 | 1,858 | 2,275 | 2,554 | 2,434 | 2,009 | 1,779 | 1,884 | 2,142 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2016 | Feb. 2016 | Mar. 2016 | Apr. 2016 | May. 2016 | Jun. 2016 | Jul. 2016 | Aug. 2016 | Sep. 2016 | Oct. 2016 | Nov. 2016 | Dec. 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -64 | -62 | -61 | -61 | -85 | -117 | -146 | -142 | -109 | -72 | -64 | -63 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,743 | 2,551 | 2,461 | 2,057 | 3,153 | 3,656 | 3,740 | 3,404 | 3,096 | 2,246 | 2,579 | 3,019 |
| System Peak (1 Hour) | 2,743 | 2,551 | 2,461 | 2,057 | 3,153 | 3,656 | 3,740 | 3,404 | 3,096 | 2,246 | 2,579 | 3,019 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,743 | 2,551 | 2,461 | 2,057 | 3,153 | 3,656 | 3,740 | 3,404 | 3,096 | 2,246 | 2,579 | 3,019 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2017 | Feb. 2017 | Mar. 2017 | Apr. 2017 | May. 2017 | Jun. 2017 | Jul. 2017 | Aug. 2017 | Sep. 2017 | Oct. 2017 | Nov. 2017 | Dec. 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 879 | 774 | 669 | 518 | 490 | 579 | 699 | 704 | 558 | 571 | 717 | 905 |
| Commercial | 551 | 531 | 510 | 449 | 476 | 542 | 581 | 580 | 518 | 505 | 519 | 559 |
| Irrigation | 0 | 0 | 4 | 76 | 234 | 474 | 567 | 452 | 279 | 65 | 2 | 2 |
| Industrial | 321 | 311 | 311 | 304 | 311 | 331 | 324 | 330 | 326 | 332 | 327 | 326 |
| Additional Firm | 171 | 171 | 168 | 166 | 166 | 157 | 168 | 166 | 162 | 164 | 168 | 172 |
| Loss | 169 | 156 | 145 | 170 | 193 | 208 | 236 | 224 | 181 | 157 | 166 | 191 |
| Firm Load | 2,092 | 1,944 | 1,806 | 1,683 | 1,868 | 2,291 | 2,575 | 2,455 | 2,025 | 1,793 | 1,899 | 2,156 |
| Light Load | 1,934 | 1,812 | 1,671 | 1,516 | 1,677 | 2,072 | 2,307 | 2,198 | 1,808 | 1,607 | 1,764 | 2,001 |
| Heavy Load | 2,217 | 2,042 | 1,904 | 1,816 | 2,019 | 2,452 | 2,805 | 2,640 | 2,198 | 1,941 | 2,007 | 2,290 |
| System Load | 2,092 | 1,944 | 1,806 | 1,683 | 1,868 | 2,291 | 2,575 | 2,455 | 2,025 | 1,793 | 1,899 | 2,156 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,092 | 1,944 | 1,806 | 1,683 | 1,868 | 2,291 | 2,575 | 2,455 | 2,025 | 1,793 | 1,899 | 2,156 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2017 | Feb. 2017 | Mar. 2017 | Apr. 2017 | May. 2017 | Jun. 2017 | Jul. 2017 | Aug. 2017 | Sep. 2017 | Oct. 2017 | Nov. 2017 | Dec. 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -70 | -68 | -67 | -67 | -92 | -126 | -157 | -154 | -119 | -79 | -70 | -69 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,760 | 2,568 | 2,478 | 2,070 | 3,199 | 3,681 | 3,792 | 3,401 | 3,141 | 2,260 | 2,595 | 2,916 |
| System Peak (1 Hour) | 2,760 | 2,568 | 2,478 | 2,070 | 3,199 | 3,681 | 3,792 | 3,401 | 3,141 | 2,260 | 2,595 | 2,916 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,760 | 2,568 | 2,478 | 2,070 | 3,199 | 3,681 | 3,792 | 3,401 | 3,141 | 2,260 | 2,595 | 2,916 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2018 | Feb. 2018 | Mar. 2018 | Apr. 2018 | May. 2018 | Jun. 2018 | Jul. 2018 | Aug. 2018 | Sep. 2018 | Oct. 2018 | Nov. 2018 | Dec. 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 882 | 776 | 671 | 519 | 492 | 585 | 709 | 714 | 564 | 575 | 723 | 915 |
| Commercial | 554 | 534 | 513 | 452 | 479 | 548 | 586 | 585 | 523 | 509 | 522 | 566 |
| Irrigation | 0 | 0 | 4 | 77 | 234 | 474 | 567 | 452 | 280 | 65 | 2 | 2 |
| Industrial | 327 | 316 | 317 | 309 | 316 | 337 | 329 | 336 | 332 | 337 | 332 | 332 |
| Additional Firm | 171 | 171 | 168 | 166 | 166 | 157 | 168 | 166 | 162 | 164 | 168 | 172 |
| Loss | 170 | 157 | 146 | 171 | 194 | 210 | 239 | 226 | 182 | 158 | 168 | 194 |
| Firm Load | 2,104 | 1,954 | 1,818 | 1,693 | 1,881 | 2,311 | 2,599 | 2,479 | 2,043 | 1,809 | 1,914 | 2,180 |
| Light Load | 1,945 | 1,822 | 1,682 | 1,525 | 1,688 | 2,090 | 2,329 | 2,219 | 1,824 | 1,620 | 1,779 | 2,024 |
| Heavy Load | 2,230 | 2,053 | 1,916 | 1,827 | 2,032 | 2,473 | 2,831 | 2,666 | 2,234 | 1,945 | 2,023 | 2,315 |
| System Load | 2,104 | 1,954 | 1,818 | 1,693 | 1,881 | 2,311 | 2,599 | 2,479 | 2,043 | 1,809 | 1,914 | 2,180 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,104 | 1,954 | 1,818 | 1,693 | 1,881 | 2,311 | 2,599 | 2,479 | 2,043 | 1,809 | 1,914 | 2,180 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2018 | Feb. 2018 | Mar. 2018 | Apr. 2018 | May. 2018 | Jun. 2018 | Jul. 2018 | Aug. 2018 | Sep. 2018 | Oct. 2018 | Nov. 2018 | Dec. 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -76 | -74 | -72 | -72 | -99 | -134 | -168 | -165 | -127 | -85 | -75 | -74 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,741 | 2,552 | 2,432 | 2,023 | 3,246 | 3,737 | 3,847 | 3,452 | 3,188 | 2,274 | 2,611 | 2,954 |
| System Peak (1 Hour) | 2,741 | 2,552 | 2,432 | 2,023 | 3,246 | 3,737 | 3,847 | 3,452 | 3,188 | 2,274 | 2,611 | 2,954 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,741 | 2,552 | 2,432 | 2,023 | 3,246 | 3,737 | 3,847 | 3,452 | 3,188 | 2,274 | 2,611 | 2,954 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2019 | Feb. 2019 | Mar. 2019 | Apr. 2019 | May. 2019 | Jun. 2019 | Jul. 2019 | Aug. 2019 | Sep. 2019 | Oct. 2019 | Nov. 2019 | Dec. 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 892 | 784 | 678 | 524 | 497 | 596 | 726 | 730 | 574 | 585 | 734 | 929 |
| Commercial | 563 | 543 | 523 | 461 | 489 | 560 | 599 | 598 | 534 | 519 | 532 | 576 |
| Irrigation | 0 | 0 | 4 | 77 | 234 | 475 | 568 | 453 | 280 | 65 | 2 | 2 |
| Industrial | 332 | 321 | 322 | 314 | 321 | 343 | 335 | 342 | 337 | 343 | 338 | 337 |
| Additional Firm | 171 | 171 | 168 | 166 | 166 | 157 | 168 | 166 | 162 | 164 | 168 | 172 |
| Loss | 173 | 159 | 148 | 173 | 197 | 213 | 242 | 230 | 185 | 161 | 170 | 197 |
| Firm Load | 2,132 | 1,978 | 1,842 | 1,713 | 1,904 | 2,345 | 2,638 | 2,518 | 2,073 | 1,837 | 1,943 | 2,213 |
| Light Load | 1,971 | 1,845 | 1,704 | 1,544 | 1,709 | 2,120 | 2,364 | 2,255 | 1,851 | 1,645 | 1,805 | 2,054 |
| Heavy Load | 2,258 | 2,079 | 1,951 | 1,837 | 2,058 | 2,524 | 2,854 | 2,708 | 2,268 | 1,975 | 2,053 | 2,350 |
| System Load | 2,132 | 1,978 | 1,842 | 1,713 | 1,904 | 2,345 | 2,638 | 2,518 | 2,073 | 1,837 | 1,943 | 2,213 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,132 | 1,978 | 1,842 | 1,713 | 1,904 | 2,345 | 2,638 | 2,518 | 2,073 | 1,837 | 1,943 | 2,213 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2019 | Feb. 2019 | Mar. 2019 | Apr. 2019 | May. 2019 | Jun. 2019 | Jul. 2019 | Aug. 2019 | Sep. 2019 | Oct. 2019 | Nov. 2019 | Dec. 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -82 | -79 | -78 | -78 | -106 | -142 | -179 | -175 | -136 | -91 | -81 | -80 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,771 | 2,572 | 2,461 | 2,040 | 3,296 | 3,804 | 3,916 | 3,520 | 3,235 | 2,300 | 2,641 | 3,014 |
| System Peak (1 Hour) | 2,771 | 2,572 | 2,461 | 2,040 | 3,296 | 3,804 | 3,916 | 3,520 | 3,235 | 2,300 | 2,641 | 3,014 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,771 | 2,572 | 2,461 | 2,040 | 3,296 | 3,804 | 3,916 | 3,520 | 3,235 | 2,300 | 2,641 | 3,014 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2020 | Feb. 2020 | Mar. 2020 | Apr. 2020 | May. 2020 | Jun. 2020 | Jul. 2020 | Aug. 2020 | Sep. 2020 | Oct. 2020 | Nov. 2020 | Dec. 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 905 | 793 | 687 | 529 | 504 | 609 | 744 | 748 | 587 | 596 | 746 | 944 |
| Commercial | 574 | 553 | 534 | 470 | 500 | 574 | 614 | 613 | 545 | 531 | 542 | 587 |
| Irrigation | 0 | 0 | 4 | 77 | 235 | 476 | 569 | 454 | 281 | 65 | 2 | 2 |
| Industrial | 337 | 326 | 327 | 319 | 327 | 348 | 341 | 348 | 343 | 349 | 344 | 343 |
| Additional Firm | 171 | 169 | 168 | 166 | 166 | 157 | 168 | 166 | 162 | 164 | 168 | 172 |
| Loss | 175 | 161 | 150 | 175 | 200 | 216 | 247 | 234 | 188 | 164 | 173 | 200 |
| Firm Load | 2,162 | 2,004 | 1,869 | 1,736 | 1,931 | 2,381 | 2,682 | 2,562 | 2,107 | 1,868 | 1,975 | 2,248 |
| Light Load | 1,999 | 1,869 | 1,729 | 1,565 | 1,734 | 2,152 | 2,404 | 2,294 | 1,881 | 1,673 | 1,835 | 2,086 |
| Heavy Load | 2,291 | 2,104 | 1,980 | 1,862 | 2,101 | 2,548 | 2,902 | 2,774 | 2,287 | 2,009 | 2,097 | 2,375 |
| System Load | 2,162 | 2,004 | 1,869 | 1,736 | 1,931 | 2,381 | 2,682 | 2,562 | 2,107 | 1,868 | 1,975 | 2,248 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,162 | 2,004 | 1,869 | 1,736 | 1,931 | 2,381 | 2,682 | 2,562 | 2,107 | 1,868 | 1,975 | 2,248 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2020 | Feb. 2020 | Mar. 2020 | Apr. 2020 | May. 2020 | Jun. 2020 | Jul. 2020 | Aug. 2020 | Sep. 2020 | Oct. 2020 | Nov. 2020 | Dec. 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -87 | -84 | -83 | -83 | -111 | -150 | -190 | -185 | -144 | -96 | -86 | -85 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,808 | 2,596 | 2,498 | 2,065 | 3,349 | 3,874 | 3,990 | 3,592 | 3,282 | 2,330 | 2,674 | 3,078 |
| System Peak (1 Hour) | 2,808 | 2,596 | 2,498 | 2,065 | 3,349 | 3,874 | 3,990 | 3,592 | 3,282 | 2,330 | 2,674 | 3,078 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,808 | 2,596 | 2,498 | 2,065 | 3,349 | 3,874 | 3,990 | 3,592 | 3,282 | 2,330 | 2,674 | 3,078 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2021 | Feb. 2021 | Mar. 2021 | Apr. 2021 | May. 2021 | Jun. 2021 | Jul. 2021 | Aug. 2021 | Sep. 2021 | Oct. 2021 | Nov. 2021 | Dec. 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 917 | 803 | 696 | 535 | 511 | 622 | 762 | 767 | 600 | 607 | 759 | 960 |
| Commercial | 585 | 564 | 545 | 480 | 512 | 588 | 629 | 627 | 558 | 542 | 553 | 598 |
| Irrigation | 0 | 0 | 4 | 77 | 235 | 477 | 570 | 455 | 281 | 65 | 2 | 2 |
| Industrial | 344 | 333 | 334 | 325 | 333 | 355 | 347 | 355 | 350 | 356 | 350 | 350 |
| Additional Firm | 170 | 171 | 167 | 165 | 165 | 156 | 168 | 165 | 162 | 164 | 167 | 171 |
| Loss | 178 | 164 | 152 | 178 | 203 | 220 | 251 | 239 | 192 | 167 | 176 | 203 |
| Firm Load | 2,195 | 2,034 | 1,897 | 1,760 | 1,959 | 2,418 | 2,728 | 2,607 | 2,142 | 1,900 | 2,007 | 2,284 |
| Light Load | 2,029 | 1,897 | 1,755 | 1,586 | 1,759 | 2,186 | 2,445 | 2,335 | 1,913 | 1,702 | 1,865 | 2,119 |
| Heavy Load | 2,338 | 2,138 | 1,999 | 1,888 | 2,132 | 2,588 | 2,932 | 2,822 | 2,326 | 2,057 | 2,121 | 2,413 |
| System Load | 2,195 | 2,034 | 1,897 | 1,760 | 1,959 | 2,418 | 2,728 | 2,607 | 2,142 | 1,900 | 2,007 | 2,284 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,195 | 2,034 | 1,897 | 1,760 | 1,959 | 2,418 | 2,728 | 2,607 | 2,142 | 1,900 | 2,007 | 2,284 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2021 | Feb. 2021 | Mar. 2021 | Apr. 2021 | May. 2021 | Jun. 2021 | Jul. 2021 | Aug. 2021 | Sep. 2021 | Oct. 2021 | Nov. 2021 | Dec. 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -92 | -90 | -88 | -88 | -117 | -159 | -200 | -195 | -152 | -102 | -92 | -91 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,847 | 2,623 | 2,538 | 2,092 | 3,402 | 3,945 | 4,066 | 3,664 | 3,329 | 2,361 | 2,708 | 3,143 |
| System Peak (1 Hour) | 2,847 | 2,623 | 2,538 | 2,092 | 3,402 | 3,945 | 4,066 | 3,664 | 3,329 | 2,361 | 2,708 | 3,143 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,847 | 2,623 | 2,538 | 2,092 | 3,402 | 3,945 | 4,066 | 3,664 | 3,329 | 2,361 | 2,708 | 3,143 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2022 | Feb. 2022 | Mar. 2022 | Apr. 2022 | May. 2022 | Jun. 2022 | Jul. 2022 | Aug. 2022 | Sep. 2022 | Oct. 2022 | Nov. 2022 | Dec. 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 930 | 813 | 705 | 541 | 518 | 635 | 781 | 787 | 613 | 618 | 772 | 975 |
| Commercial | 596 | 575 | 556 | 490 | 523 | 602 | 646 | 642 | 571 | 555 | 564 | 609 |
| Irrigation | 0 | 0 | 4 | 77 | 236 | 478 | 572 | 456 | 282 | 65 | 2 | 2 |
| Industrial | 350 | 338 | 339 | 331 | 339 | 361 | 354 | 361 | 355 | 362 | 356 | 356 |
| Additional Firm | 170 | 171 | 167 | 165 | 165 | 156 | 168 | 165 | 162 | 164 | 167 | 171 |
| Loss | 180 | 166 | 154 | 180 | 206 | 223 | 255 | 243 | 195 | 169 | 179 | 206 |
| Firm Load | 2,227 | 2,063 | 1,925 | 1,785 | 1,987 | 2,457 | 2,775 | 2,654 | 2,178 | 1,933 | 2,040 | 2,320 |
| Light Load | 2,059 | 1,924 | 1,781 | 1,608 | 1,784 | 2,221 | 2,487 | 2,376 | 1,945 | 1,732 | 1,896 | 2,153 |
| Heavy Load | 2,372 | 2,168 | 2,029 | 1,914 | 2,162 | 2,629 | 3,023 | 2,854 | 2,365 | 2,092 | 2,156 | 2,440 |
| System Load | 2,227 | 2,063 | 1,925 | 1,785 | 1,987 | 2,457 | 2,775 | 2,654 | 2,178 | 1,933 | 2,040 | 2,320 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,227 | 2,063 | 1,925 | 1,785 | 1,987 | 2,457 | 2,775 | 2,654 | 2,178 | 1,933 | 2,040 | 2,320 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2022 | Feb. 2022 | Mar. 2022 | Apr. 2022 | May. 2022 | Jun. 2022 | Jul. 2022 | Aug. 2022 | Sep. 2022 | Oct. 2022 | Nov. 2022 | Dec. 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -97 | -95 | -94 | -93 | -123 | -167 | -210 | -206 | -160 | -107 | -97 | -96 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,886 | 2,649 | 2,578 | 2,118 | 3,454 | 4,016 | 4,143 | 3,737 | 3,376 | 2,392 | 2,743 | 3,208 |
| System Peak (1 Hour) | 2,886 | 2,649 | 2,578 | 2,118 | 3,454 | 4,016 | 4,143 | 3,737 | 3,376 | 2,392 | 2,743 | 3,208 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,886 | 2,649 | 2,578 | 2,118 | 3,454 | 4,016 | 4,143 | 3,737 | 3,376 | 2,392 | 2,743 | 3,208 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2023 | Feb. 2023 | Mar. 2023 | Apr. 2023 | May. 2023 | Jun. 2023 | Jul. 2023 | Aug. 2023 | Sep. 2023 | Oct. 2023 | Nov. 2023 | Dec. 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 942 | 822 | 713 | 547 | 525 | 648 | 801 | 807 | 625 | 629 | 785 | 990 |
| Commercial | 608 | 586 | 568 | 500 | 535 | 618 | 662 | 657 | 585 | 567 | 575 | 621 |
| Irrigation | 0 | 0 | 4 | 77 | 236 | 479 | 573 | 457 | 283 | 65 | 2 | 2 |
| Industrial | 356 | 344 | 345 | 337 | 345 | 368 | 360 | 367 | 362 | 368 | 362 | 362 |
| Additional Firm | 169 | 169 | 166 | 164 | 164 | 155 | 167 | 164 | 161 | 163 | 166 | 170 |
| Loss | 183 | 168 | 157 | 183 | 209 | 227 | 260 | 247 | 198 | 172 | 182 | 210 |
| Firm Load | 2,258 | 2,090 | 1,952 | 1,809 | 2,014 | 2,495 | 2,822 | 2,699 | 2,213 | 1,965 | 2,073 | 2,355 |
| Light Load | 2,088 | 1,949 | 1,806 | 1,630 | 1,807 | 2,255 | 2,529 | 2,417 | 1,976 | 1,760 | 1,926 | 2,186 |
| Heavy Load | 2,393 | 2,196 | 2,058 | 1,952 | 2,176 | 2,670 | 3,074 | 2,903 | 2,403 | 2,126 | 2,190 | 2,501 |
| System Load | 2,258 | 2,090 | 1,952 | 1,809 | 2,014 | 2,495 | 2,822 | 2,699 | 2,213 | 1,965 | 2,073 | 2,355 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,258 | 2,090 | 1,952 | 1,809 | 2,014 | 2,495 | 2,822 | 2,699 | 2,213 | 1,965 | 2,073 | 2,355 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2023 | Feb. 2023 | Mar. 2023 | Apr. 2023 | May. 2023 | Jun. 2023 | Jul. 2023 | Aug. 2023 | Sep. 2023 | Oct. 2023 | Nov. 2023 | Dec. 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -103 | -100 | -99 | -98 | -130 | -174 | -219 | -216 | -169 | -112 | -102 | -101 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,923 | 2,673 | 2,616 | 2,144 | 3,506 | 4,087 | 4,220 | 3,809 | 3,423 | 2,422 | 2,777 | 3,271 |
| System Peak (1 Hour) | 2,923 | 2,673 | 2,616 | 2,144 | 3,506 | 4,087 | 4,220 | 3,809 | 3,423 | 2,422 | 2,777 | 3,271 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,923 | 2,673 | 2,616 | 2,144 | 3,506 | 4,087 | 4,220 | 3,809 | 3,423 | 2,422 | 2,777 | 3,271 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2024 | Feb. 2024 | Mar. 2024 | Apr. 2024 | May. 2024 | Jun. 2024 | Jul. 2024 | Aug. 2024 | Sep. 2024 | Oct. 2024 | Nov. 2024 | Dec. 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 955 | 832 | 722 | 553 | 532 | 661 | 822 | 827 | 638 | 641 | 798 | 1,006 |
| Commercial | 619 | 597 | 580 | 511 | 547 | 634 | 678 | 674 | 599 | 580 | 587 | 633 |
| Irrigation | 0 | 0 | 4 | 77 | 237 | 480 | 574 | 457 | 283 | 66 | 2 | 2 |
| Industrial | 361 | 349 | 351 | 342 | 350 | 374 | 365 | 373 | 367 | 373 | 368 | 368 |
| Additional Firm | 169 | 167 | 166 | 164 | 164 | 155 | 167 | 164 | 161 | 163 | 166 | 170 |
| Loss | 186 | 171 | 159 | 185 | 212 | 231 | 264 | 252 | 202 | 175 | 185 | 213 |
| Firm Load | 2,290 | 2,116 | 1,981 | 1,833 | 2,041 | 2,535 | 2,869 | 2,747 | 2,250 | 1,997 | 2,106 | 2,391 |
| Light Load | 2,117 | 1,973 | 1,833 | 1,651 | 1,832 | 2,292 | 2,571 | 2,459 | 2,009 | 1,789 | 1,957 | 2,219 |
| Heavy Load | 2,426 | 2,222 | 2,098 | 1,965 | 2,206 | 2,729 | 3,104 | 2,954 | 2,461 | 2,147 | 2,225 | 2,539 |
| System Load | 2,290 | 2,116 | 1,981 | 1,833 | 2,041 | 2,535 | 2,869 | 2,747 | 2,250 | 1,997 | 2,106 | 2,391 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,290 | 2,116 | 1,981 | 1,833 | 2,041 | 2,535 | 2,869 | 2,747 | 2,250 | 1,997 | 2,106 | 2,391 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2024 | Feb. 2024 | Mar. 2024 | Apr. 2024 | May. 2024 | Jun. 2024 | Jul. 2024 | Aug. 2024 | Sep. 2024 | Oct. 2024 | Nov. 2024 | Dec. 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -108 | -105 | -102 | -102 | -135 | -181 | -229 | -225 | -176 | -118 | -106 | -105 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,960 | 2,698 | 2,656 | 2,169 | 3,559 | 4,160 | 4,298 | 3,884 | 3,471 | 2,453 | 2,812 | 3,335 |
| System Peak (1 Hour) | 2,960 | 2,698 | 2,656 | 2,169 | 3,559 | 4,160 | 4,298 | 3,884 | 3,471 | 2,453 | 2,812 | 3,335 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,960 | 2,698 | 2,656 | 2,169 | 3,559 | 4,160 | 4,298 | 3,884 | 3,471 | 2,453 | 2,812 | 3,335 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2025 | Feb. 2025 | Mar. 2025 | Apr. 2025 | May. 2025 | Jun. 2025 | Jul. 2025 | Aug. 2025 | Sep. 2025 | Oct. 2025 | Nov. 2025 | Dec. 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 967 | 841 | 730 | 559 | 539 | 675 | 842 | 847 | 652 | 652 | 811 | 1,022 |
| Commercial | 631 | 609 | 592 | 522 | 560 | 650 | 695 | 691 | 613 | 593 | 599 | 644 |
| Irrigation | 0 | 0 | 4 | 77 | 237 | 481 | 575 | 458 | 284 | 66 | 2 | 2 |
| Industrial | 368 | 356 | 358 | 348 | 357 | 381 | 372 | 381 | 375 | 381 | 376 | 375 |
| Additional Firm | 167 | 168 | 165 | 163 | 163 | 154 | 166 | 163 | 160 | 162 | 164 | 168 |
| Loss | 188 | 173 | 161 | 188 | 215 | 234 | 269 | 256 | 205 | 178 | 188 | 216 |
| Firm Load | 2,322 | 2,147 | 2,010 | 1,858 | 2,071 | 2,576 | 2,919 | 2,797 | 2,288 | 2,031 | 2,140 | 2,428 |
| Light Load | 2,147 | 2,002 | 1,860 | 1,674 | 1,859 | 2,329 | 2,616 | 2,504 | 2,043 | 1,819 | 1,989 | 2,253 |
| Heavy Load | 2,460 | 2,256 | 2,129 | 1,992 | 2,238 | 2,773 | 3,158 | 3,027 | 2,484 | 2,184 | 2,273 | 2,565 |
| System Load | 2,322 | 2,147 | 2,010 | 1,858 | 2,071 | 2,576 | 2,919 | 2,797 | 2,288 | 2,031 | 2,140 | 2,428 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,322 | 2,147 | 2,010 | 1,858 | 2,071 | 2,576 | 2,919 | 2,797 | 2,288 | 2,031 | 2,140 | 2,428 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2025 | Feb. 2025 | Mar. 2025 | Apr. 2025 | May. 2025 | Jun. 2025 | Jul. 2025 | Aug. 2025 | Sep. 2025 | Oct. 2025 | Nov. 2025 | Dec. 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -113 | -110 | -107 | -107 | -141 | -188 | -239 | -234 | -184 | -123 | -111 | -111 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,999 | 2,725 | 2,697 | 2,196 | 3,612 | 4,233 | 4,378 | 3,960 | 3,517 | 2,485 | 2,849 | 3,400 |
| System Peak (1 Hour) | 2,999 | 2,725 | 2,697 | 2,196 | 3,612 | 4,233 | 4,378 | 3,960 | 3,517 | 2,485 | 2,849 | 3,400 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,999 | 2,725 | 2,697 | 2,196 | 3,612 | 4,233 | 4,378 | 3,960 | 3,517 | 2,485 | 2,849 | 3,400 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2026 | Feb. 2026 | Mar. 2026 | Apr. 2026 | May. 2026 | Jun. 2026 | Jul. 2026 | Aug. 2026 | Sep. 2026 | Oct. 2026 | Nov. 2026 | Dec. 2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 980 | 851 | 739 | 565 | 547 | 690 | 865 | 870 | 667 | 664 | 825 | 1,038 |
| Commercial | 643 | 621 | 605 | 533 | 573 | 666 | 714 | 709 | 628 | 606 | 611 | 656 |
| Irrigation | 0 | 0 | 4 | 78 | 238 | 482 | 576 | 459 | 284 | 66 | 2 | 2 |
| Industrial | 378 | 365 | 367 | 357 | 366 | 391 | 382 | 391 | 384 | 391 | 385 | 385 |
| Additional Firm | 166 | 166 | 163 | 162 | 162 | 153 | 164 | 162 | 159 | 160 | 163 | 167 |
| Loss | 191 | 176 | 164 | 191 | 218 | 239 | 274 | 262 | 209 | 182 | 192 | 220 |
| Firm Load | 2,358 | 2,179 | 2,042 | 1,886 | 2,103 | 2,621 | 2,974 | 2,852 | 2,331 | 2,069 | 2,178 | 2,468 |
| Light Load | 2,180 | 2,032 | 1,890 | 1,699 | 1,888 | 2,370 | 2,665 | 2,554 | 2,081 | 1,853 | 2,024 | 2,290 |
| Heavy Load | 2,498 | 2,290 | 2,163 | 2,022 | 2,288 | 2,805 | 3,218 | 3,087 | 2,531 | 2,224 | 2,313 | 2,607 |
| System Load | 2,358 | 2,179 | 2,042 | 1,886 | 2,103 | 2,621 | 2,974 | 2,852 | 2,331 | 2,069 | 2,178 | 2,468 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,358 | 2,179 | 2,042 | 1,886 | 2,103 | 2,621 | 2,974 | 2,852 | 2,331 | 2,069 | 2,178 | 2,468 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2026 | Feb. 2026 | Mar. 2026 | Apr. 2026 | May. 2026 | Jun. 2026 | Jul. 2026 | Aug. 2026 | Sep. 2026 | Oct. 2026 | Nov. 2026 | Dec. 2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -114 | -111 | -108 | -108 | -142 | -191 | -243 | -238 | -187 | -124 | -112 | -112 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 3,042 | 2,755 | 2,742 | 2,225 | 3,670 | 4,310 | 4,464 | 4,041 | 3,569 | 2,521 | 2,889 | 3,467 |
| System Peak (1 Hour) | 3,042 | 2,755 | 2,742 | 2,225 | 3,670 | 4,310 | 4,464 | 4,041 | 3,569 | 2,521 | 2,889 | 3,467 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 3,042 | 2,755 | 2,742 | 2,225 | 3,670 | 4,310 | 4,464 | 4,041 | 3,569 | 2,521 | 2,889 | 3,467 |

## Expected Case Sales and Load Forecast

### Average Load (aMW) - 50th Percentile

| | Jan. 2027 | Feb. 2027 | Mar. 2027 | Apr. 2027 | May. 2027 | Jun. 2027 | Jul. 2027 | Aug. 2027 | Sep. 2027 | Oct. 2027 | Nov. 2027 | Dec. 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 993 | 860 | 748 | 571 | 554 | 705 | 887 | 892 | 681 | 676 | 839 | 1,053 |
| Commercial | 654 | 632 | 617 | 544 | 586 | 683 | 732 | 726 | 643 | 619 | 623 | 668 |
| Irrigation | 0 | 0 | 4 | 78 | 238 | 483 | 577 | 460 | 285 | 66 | 2 | 2 |
| Industrial | 388 | 375 | 377 | 367 | 376 | 401 | 391 | 401 | 394 | 401 | 395 | 394 |
| Additional Firm | 164 | 165 | 162 | 160 | 161 | 152 | 163 | 161 | 158 | 159 | 162 | 166 |
| Loss | 194 | 178 | 167 | 194 | 222 | 243 | 279 | 267 | 213 | 185 | 195 | 224 |
| Firm Load | 2,394 | 2,211 | 2,074 | 1,914 | 2,136 | 2,667 | 3,030 | 2,907 | 2,374 | 2,106 | 2,215 | 2,507 |
| Light Load | 2,213 | 2,061 | 1,919 | 1,724 | 1,917 | 2,411 | 2,715 | 2,603 | 2,119 | 1,887 | 2,058 | 2,326 |
| Heavy Load | 2,549 | 2,323 | 2,186 | 2,052 | 2,324 | 2,854 | 3,257 | 3,147 | 2,577 | 2,280 | 2,341 | 2,649 |
| System Load | 2,394 | 2,211 | 2,074 | 1,914 | 2,136 | 2,667 | 3,030 | 2,907 | 2,374 | 2,106 | 2,215 | 2,507 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,394 | 2,211 | 2,074 | 1,914 | 2,136 | 2,667 | 3,030 | 2,907 | 2,374 | 2,106 | 2,215 | 2,507 |

### Peak Load (MW) - 90th Percentile

| | Jan. 2027 | Feb. 2027 | Mar. 2027 | Apr. 2027 | May. 2027 | Jun. 2027 | Jul. 2027 | Aug. 2027 | Sep. 2027 | Oct. 2027 | Nov. 2027 | Dec. 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -115 | -112 | -109 | -109 | -144 | -193 | -247 | -242 | -189 | -125 | -113 | -113 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 3,083 | 2,784 | 2,785 | 2,255 | 3,727 | 4,387 | 4,550 | 4,121 | 3,621 | 2,557 | 2,928 | 3,531 |
| System Peak (1 Hour) | 3,083 | 2,784 | 2,785 | 2,255 | 3,727 | 4,387 | 4,550 | 4,121 | 3,621 | 2,557 | 2,928 | 3,531 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 3,083 | 2,784 | 2,785 | 2,255 | 3,727 | 4,387 | 4,550 | 4,121 | 3,621 | 2,557 | 2,928 | 3,531 |

## Expected Case Sales and Load Forecast Annual Summary

### Billed Sales (MWh) - 50th Percentile

| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 5,272,077 | 5,381,084 | 5,466,252 | 5,559,713 | 5,611,397 | 5,667,256 | 5,703,306 | 5,741,952 | 5,840,664 | 5,883,023 |
| Commercial | 3,991,985 | 4,073,751 | 4,163,884 | 4,248,344 | 4,312,482 | 4,379,893 | 4,428,980 | 4,478,747 | 4,568,202 | 4,614,066 |
| Irrigation | 1,606,077 | 1,602,642 | 1,600,993 | 1,597,335 | 1,593,692 | 1,590,815 | 1,582,340 | 1,585,301 | 1,588,210 | 1,582,580 |
| Industrial | 2,411,609 | 2,460,859 | 2,515,918 | 2,563,563 | 2,607,249 | 2,650,684 | 2,685,765 | 2,732,383 | 2,781,434 | 2,810,881 |
| Additional Firm | 1,168,602 | 1,472,472 | 1,509,783 | 1,512,208 | 1,468,718 | 1,466,455 | 1,462,890 | 1,463,064 | 1,466,036 | 1,459,239 |
| Firm Sales | 14,450,350 | 14,990,809 | 15,256,830 | 15,481,163 | 15,593,539 | 15,755,103 | 15,863,280 | 16,001,447 | 16,244,546 | 16,349,789 |
| System Sales | 14,450,350 | 14,990,809 | 15,256,830 | 15,481,163 | 15,593,539 | 15,755,103 | 15,863,280 | 16,001,447 | 16,244,546 | 16,349,789 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Sales | 14,450,350 | 14,990,809 | 15,256,830 | 15,481,163 | 15,593,539 | 15,755,103 | 15,863,280 | 16,001,447 | 16,244,546 | 16,349,789 |

### Generation Month Sales (MWh) - 50th Percentile

| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 5,297,677 | 5,387,546 | 5,473,222 | 5,563,755 | 5,633,969 | 5,670,071 | 5,706,137 | 5,748,742 | 5,862,441 | 5,885,934 |
| Commercial | 4,007,512 | 4,078,664 | 4,168,703 | 4,252,150 | 4,328,584 | 4,382,877 | 4,431,746 | 4,483,550 | 4,583,640 | 4,615,808 |
| Irrigation | 1,606,088 | 1,602,646 | 1,600,995 | 1,597,336 | 1,593,701 | 1,590,812 | 1,582,342 | 1,585,303 | 1,588,213 | 1,582,582 |
| Industrial | 2,414,715 | 2,465,851 | 2,520,663 | 2,567,677 | 2,610,442 | 2,655,148 | 2,688,627 | 2,736,533 | 2,785,052 | 2,814,178 |
| Additional Firm | 1,168,602 | 1,472,472 | 1,509,783 | 1,512,208 | 1,468,718 | 1,466,455 | 1,462,890 | 1,463,064 | 1,466,036 | 1,459,239 |
| Firm Sales | 14,494,594 | 15,007,180 | 15,273,365 | 15,493,126 | 15,635,415 | 15,765,363 | 15,871,743 | 16,017,192 | 16,285,383 | 16,357,740 |
| System Sales | 14,494,594 | 15,007,180 | 15,273,365 | 15,493,126 | 15,635,415 | 15,765,363 | 15,871,743 | 16,017,192 | 16,285,383 | 16,357,740 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Sales | 14,494,594 | 15,007,180 | 15,273,365 | 15,493,126 | 15,635,415 | 15,765,363 | 15,871,743 | 16,017,192 | 16,285,383 | 16,357,740 |
| Loss | 1,423,205 | 1,460,117 | 1,486,470 | 1,509,866 | 1,527,755 | 1,542,542 | 1,554,939 | 1,569,728 | 1,597,326 | 1,605,687 |
| Required Generation | 15,917,799 | 16,467,297 | 16,759,835 | 17,002,992 | 17,163,169 | 17,307,905 | 17,426,682 | 17,586,921 | 17,882,709 | 17,963,427 |

### Average Load (aMW) - 50th Percentile

| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 603 | 615 | 625 | 635 | 641 | 647 | 651 | 656 | 667 | 672 |
| Commercial | 456 | 466 | 476 | 485 | 493 | 500 | 506 | 512 | 522 | 527 |
| Irrigation | 183 | 183 | 183 | 182 | 181 | 182 | 181 | 181 | 181 | 181 |
| Industrial | 275 | 281 | 288 | 293 | 297 | 303 | 307 | 312 | 317 | 321 |
| Additional Firm | 133 | 168 | 172 | 173 | 167 | 167 | 167 | 167 | 167 | 167 |
| Loss | 162 | 167 | 170 | 172 | 174 | 176 | 178 | 179 | 182 | 183 |
| Firm Load | 1,812 | 1,880 | 1,913 | 1,941 | 1,954 | 1,976 | 1,989 | 2,008 | 2,036 | 2,051 |
| Light Load | 1,648 | 1,710 | 1,740 | 1,766 | 1,777 | 1,797 | 1,810 | 1,826 | 1,852 | 1,865 |
| Heavy Load | 1,940 | 2,013 | 2,048 | 2,078 | 2,093 | 2,116 | 2,130 | 2,150 | 2,180 | 2,196 |
| System Load | 1,812 | 1,880 | 1,913 | 1,941 | 1,954 | 1,976 | 1,989 | 2,008 | 2,036 | 2,051 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,812 | 1,880 | 1,913 | 1,941 | 1,954 | 1,976 | 1,989 | 2,008 | 2,036 | 2,051 |

### Peak Load (MW) - 90th Percentile

| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (Mw) | -30 | -46 | -61 | -76 | -92 | -107 | -123 | -135 | -146 | -157 |
| Demand Response (Mw) | -66 | -78 | -82 | -82 | -82 | -82 | -82 | -82 | -82 | -82 |
| Firm Peak Load | 3,240 | 3,338 | 3,400 | 3,464 | 3,510 | 3,567 | 3,615 | 3,671 | 3,740 | 3,792 |
| System Peak (1 Hour) | 3,240 | 3,338 | 3,400 | 3,464 | 3,510 | 3,567 | 3,615 | 3,671 | 3,740 | 3,792 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loss | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 3,240 | 3,338 | 3,400 | 3,464 | 3,510 | 3,567 | 3,615 | 3,671 | 3,740 | 3,792 |

## Expected Case Sales and Load Forecast Annual Summary

### Billed Sales (MWh) - 50th Percentile

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 5,925,711 | 6,015,087 | 6,119,743 | 6,227,718 | 6,336,936 | 6,445,662 | 6,554,914 | 6,665,539 | 6,785,280 | 6,901,453 |
| Commercial | 4,648,002 | 4,739,205 | 4,841,226 | 4,946,104 | 5,055,592 | 5,166,266 | 5,281,491 | 5,398,487 | 5,519,360 | 5,639,585 |
| Irrigation | 1,584,791 | 1,587,750 | 1,590,824 | 1,593,872 | 1,596,871 | 1,599,866 | 1,602,860 | 1,605,908 | 1,608,864 | 1,611,660 |
| Industrial | 2,857,163 | 2,905,486 | 2,962,268 | 3,012,134 | 3,064,480 | 3,117,298 | 3,172,855 | 3,227,871 | 3,309,541 | 3,394,606 |
| Additional Firm | 1,458,939 | 1,458,839 | 1,461,536 | 1,454,039 | 1,453,139 | 1,443,139 | 1,445,036 | 1,432,339 | 1,421,239 | 1,411,239 |
| Firm Sales | 16,474,607 | 16,706,367 | 16,975,598 | 17,233,866 | 17,507,018 | 17,772,230 | 18,057,157 | 18,330,143 | 18,644,284 | 18,958,542 |
| System Sales | 16,474,607 | 16,706,367 | 16,975,598 | 17,233,866 | 17,507,018 | 17,772,230 | 18,057,157 | 18,330,143 | 18,644,284 | 18,958,542 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Sales | 16,474,607 | 16,706,367 | 16,975,598 | 17,233,866 | 17,507,018 | 17,772,230 | 18,057,157 | 18,330,143 | 18,644,284 | 18,958,542 |

### Generation Month Sales (MWh) - 50th Percentile

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 5,931,730 | 6,022,095 | 6,146,444 | 6,234,970 | 6,344,126 | 6,452,856 | 6,582,711 | 6,672,866 | 6,792,338 | 6,908,179 |
| Commercial | 4,652,673 | 4,744,250 | 4,860,039 | 4,951,318 | 5,060,836 | 5,171,558 | 5,301,600 | 5,403,851 | 5,524,660 | 5,644,803 |
| Irrigation | 1,584,794 | 1,587,753 | 1,590,834 | 1,593,874 | 1,596,874 | 1,599,868 | 1,602,870 | 1,605,910 | 1,608,866 | 1,611,662 |
| Industrial | 2,861,277 | 2,909,639 | 2,966,392 | 3,017,181 | 3,069,076 | 3,122,075 | 3,176,821 | 3,233,353 | 3,316,711 | 3,401,936 |
| Additional Firm | 1,458,939 | 1,458,839 | 1,461,536 | 1,454,039 | 1,453,139 | 1,443,139 | 1,445,036 | 1,432,339 | 1,421,239 | 1,411,239 |
| Firm Sales | 16,489,412 | 16,722,575 | 17,025,246 | 17,251,381 | 17,524,050 | 17,789,495 | 18,109,038 | 18,348,318 | 18,663,814 | 18,977,819 |
| System Sales | 16,489,412 | 16,722,575 | 17,025,246 | 17,251,381 | 17,524,050 | 17,789,495 | 18,109,038 | 18,348,318 | 18,663,814 | 18,977,819 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Sales | 16,489,412 | 16,722,575 | 17,025,246 | 17,251,381 | 17,524,050 | 17,789,495 | 18,109,038 | 18,348,318 | 18,663,814 | 18,977,819 |
| Loss | 1,618,701 | 1,642,735 | 1,673,136 | 1,696,898 | 1,724,517 | 1,751,984 | 1,783,691 | 1,808,436 | 1,840,591 | 1,872,434 |
| Required Generation | 18,108,113 | 18,365,310 | 18,698,382 | 18,948,279 | 19,248,567 | 19,541,479 | 19,892,729 | 20,156,754 | 20,504,405 | 20,850,252 |

### Average Load (aMW) - 50th Percentile

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 677 | 687 | 700 | 712 | 724 | 737 | 749 | 762 | 775 | 789 |
| Commercial | 531 | 542 | 553 | 565 | 578 | 590 | 604 | 617 | 631 | 644 |
| Irrigation | 181 | 181 | 181 | 182 | 182 | 183 | 182 | 183 | 184 | 184 |
| Industrial | 327 | 332 | 338 | 344 | 350 | 356 | 362 | 369 | 379 | 388 |
| Additional Firm | 167 | 167 | 166 | 166 | 166 | 165 | 165 | 164 | 162 | 161 |
| Loss | 185 | 188 | 190 | 194 | 197 | 200 | 203 | 206 | 210 | 214 |
| Firm Load | 2,067 | 2,096 | 2,129 | 2,163 | 2,197 | 2,231 | 2,265 | 2,301 | 2,341 | 2,380 |
| Light Load | 1,880 | 1,907 | 1,936 | 1,967 | 1,999 | 2,029 | 2,060 | 2,093 | 2,129 | 2,165 |
| Heavy Load | 2,214 | 2,245 | 2,279 | 2,315 | 2,353 | 2,389 | 2,425 | 2,464 | 2,507 | 2,548 |
| System Load | 2,067 | 2,096 | 2,129 | 2,163 | 2,197 | 2,231 | 2,265 | 2,301 | 2,341 | 2,380 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,067 | 2,096 | 2,129 | 2,163 | 2,197 | 2,231 | 2,265 | 2,301 | 2,341 | 2,380 |

### Peak Load (MW) - 90th Percentile

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (Mw) | -168 | -179 | -190 | -200 | -210 | -219 | -229 | -239 | -243 | -247 |
| Demand Response (Mw) | -82 | -82 | -82 | -82 | -82 | -82 | -82 | -82 | -82 | -82 |
| Firm Peak Load | 3,847 | 3,916 | 3,990 | 4,066 | 4,143 | 4,220 | 4,298 | 4,378 | 4,464 | 4,550 |
| System Peak (1 Hour) | 3,847 | 3,916 | 3,990 | 4,066 | 4,143 | 4,220 | 4,298 | 4,378 | 4,464 | 4,550 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loss | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 3,847 | 3,916 | 3,990 | 4,066 | 4,143 | 4,220 | 4,298 | 4,378 | 4,464 | 4,550 |

**70th Percentile Average Forecast Annual Growth Rates (%)**

| | 2008–2013 | 2008–2018 | 2008–2027 |
|---|---|---|---|
| **Sales** | | | |
| Residential Sales | 1.5 | 1.2 | 1.4 |
| Commercial Sales | 1.9 | 1.5 | 1.8 |
| Irrigation Sales | -0.2 | -0.1 | 0.0 |
| Industrial Sales | 1.9 | 1.7 | 1.8 |
| Additional Firm Sales | 4.7 | 2.2 | 1.0 |
| Firm Sales | 1.7 | 1.3 | 1.4 |
| System Sales | 1.7 | 1.3 | 1.4 |
| Total Sales | 1.7 | 1.3 | 1.4 |
| **Loads** | | | |
| Residential Load | 1.5 | 1.2 | 1.4 |
| Commercial Load | 1.9 | 1.5 | 1.8 |
| Irrigation Load | -0.1 | -0.1 | 0.0 |
| Industrial Load | 2.0 | 1.7 | 1.8 |
| Additional Firm Sales | 4.7 | 2.2 | 1.0 |
| Firm Load Losses | 1.7 | 1.3 | 1.5 |
| Firm Load | 1.7 | 1.3 | 1.4 |
| System Load | 1.7 | 1.3 | 1.4 |
| Total Load | 1.7 | 1.3 | 1.4 |
| Firm Requirement Load | 1.7 | 1.3 | 1.4 |
| **Peaks** | | | |
| Firm Peak | 2.0 | 1.7 | 1.8 |
| System Peak | 2.0 | 1.7 | 1.8 |
| Total Peak | 2.0 | 1.7 | 1.8 |
| Firm Requirement Peak | 2.0 | 1.7 | 1.8 |
| Winter Peak | 1.5 | 0.6 | 1.3 |
| Summer Peak | 2.0 | 1.7 | 1.8 |
| **Customers** | | | |
| Residential Customers | 2.3 | 2.2 | 2.2 |
| Commercial Customers | 2.5 | 2.4 | 2.3 |
| Irrigation Customers | 1.6 | 1.5 | 1.4 |
| Industrial Customers | 1.4 | 1.4 | 1.3 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2008 | Feb. 2008 | Mar. 2008 | Apr. 2008 | May. 2008 | Jun. 2008 | Jul. 2008 | Aug. 2008 | Sep. 2008 | Oct. 2008 | Nov. 2008 | Dec. 2008 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 829 | 741 | 634 | 492 | 463 | 527 | 611 | 611 | 502 | 515 | 654 | 842 |
| Commercial | 492 | 471 | 447 | 396 | 417 | 465 | 498 | 501 | 447 | 436 | 457 | 501 |
| Irrigation | 0 | 0 | 4 | 104 | 288 | 533 | 602 | 476 | 300 | 75 | 3 | 2 |
| Industrial | 276 | 266 | 266 | 260 | 266 | 283 | 277 | 281 | 279 | 284 | 280 | 279 |
| Additional Firm | 140 | 137 | 135 | 133 | 132 | 122 | 133 | 131 | 128 | 131 | 135 | 140 |
| Loss | 154 | 143 | 130 | 157 | 181 | 193 | 213 | 200 | 162 | 138 | 148 | 173 |
| Firm Load | 1,891 | 1,759 | 1,617 | 1,542 | 1,747 | 2,122 | 2,335 | 2,201 | 1,819 | 1,580 | 1,675 | 1,936 |
| Light Load | 1,748 | 1,640 | 1,496 | 1,390 | 1,568 | 1,919 | 2,092 | 1,970 | 1,624 | 1,415 | 1,557 | 1,797 |
| Heavy Load | 2,003 | 1,847 | 1,712 | 1,654 | 1,887 | 2,285 | 2,526 | 2,382 | 1,975 | 1,699 | 1,779 | 2,045 |
| System Load | 1,891 | 1,759 | 1,617 | 1,542 | 1,747 | 2,122 | 2,335 | 2,201 | 1,819 | 1,580 | 1,675 | 1,936 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,891 | 1,759 | 1,617 | 1,542 | 1,747 | 2,122 | 2,335 | 2,201 | 1,819 | 1,580 | 1,675 | 1,936 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2008 | Feb. 2008 | Mar. 2008 | Apr. 2008 | May. 2008 | Jun. 2008 | Jul. 2008 | Aug. 2008 | Sep. 2008 | Oct. 2008 | Nov. 2008 | Dec. 2008 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -12 | -12 | -11 | -12 | -18 | -25 | -30 | -28 | -22 | -15 | -12 | -12 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -66 | -66 | -62 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,576 | 2,458 | 2,374 | 1,979 | 2,769 | 3,212 | 3,284 | 3,010 | 2,710 | 2,075 | 2,400 | 2,895 |
| System Peak (1 Hour) | 2,576 | 2,458 | 2,374 | 1,979 | 2,769 | 3,212 | 3,284 | 3,010 | 2,710 | 2,075 | 2,400 | 2,895 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,576 | 2,458 | 2,374 | 1,979 | 2,769 | 3,212 | 3,284 | 3,010 | 2,710 | 2,075 | 2,400 | 2,895 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2009 | Feb. 2009 | Mar. 2009 | Apr. 2009 | May. 2009 | Jun. 2009 | Jul. 2009 | Aug. 2009 | Sep. 2009 | Oct. 2009 | Nov. 2009 | Dec. 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 845 | 754 | 645 | 500 | 471 | 539 | 627 | 627 | 513 | 526 | 668 | 857 |
| Commercial | 501 | 480 | 455 | 404 | 425 | 475 | 510 | 512 | 457 | 446 | 466 | 511 |
| Irrigation | 0 | 0 | 4 | 104 | 287 | 532 | 601 | 475 | 300 | 75 | 2 | 2 |
| Industrial | 282 | 273 | 273 | 267 | 272 | 290 | 284 | 288 | 286 | 291 | 286 | 285 |
| Additional Firm | 155 | 166 | 164 | 163 | 165 | 158 | 173 | 173 | 169 | 172 | 176 | 182 |
| Loss | 157 | 147 | 134 | 161 | 186 | 198 | 219 | 206 | 167 | 143 | 152 | 178 |
| Firm Load | 1,940 | 1,819 | 1,675 | 1,599 | 1,807 | 2,192 | 2,413 | 2,281 | 1,892 | 1,653 | 1,751 | 2,015 |
| Light Load | 1,794 | 1,696 | 1,550 | 1,441 | 1,622 | 1,982 | 2,163 | 2,043 | 1,689 | 1,481 | 1,627 | 1,870 |
| Heavy Load | 2,056 | 1,912 | 1,774 | 1,715 | 1,966 | 2,346 | 2,611 | 2,469 | 2,054 | 1,777 | 1,860 | 2,129 |
| System Load | 1,940 | 1,819 | 1,675 | 1,599 | 1,807 | 2,192 | 2,413 | 2,281 | 1,892 | 1,653 | 1,751 | 2,015 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,940 | 1,819 | 1,675 | 1,599 | 1,807 | 2,192 | 2,413 | 2,281 | 1,892 | 1,653 | 1,751 | 2,015 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2009 | Feb. 2009 | Mar. 2009 | Apr. 2009 | May. 2009 | Jun. 2009 | Jul. 2009 | Aug. 2009 | Sep. 2009 | Oct. 2009 | Nov. 2009 | Dec. 2009 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -19 | -18 | -18 | -18 | -27 | -38 | -46 | -43 | -33 | -22 | -19 | -18 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -77 | -78 | -73 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,617 | 2,510 | 2,426 | 2,014 | 2,853 | 3,300 | 3,383 | 3,099 | 2,799 | 2,147 | 2,476 | 2,984 |
| System Peak (1 Hour) | 2,617 | 2,510 | 2,426 | 2,014 | 2,853 | 3,300 | 3,383 | 3,099 | 2,799 | 2,147 | 2,476 | 2,984 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,617 | 2,510 | 2,426 | 2,014 | 2,853 | 3,300 | 3,383 | 3,099 | 2,799 | 2,147 | 2,476 | 2,984 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2010 | Feb. 2010 | Mar. 2010 | Apr. 2010 | May. 2010 | Jun. 2010 | Jul. 2010 | Aug. 2010 | Sep. 2010 | Oct. 2010 | Nov. 2010 | Dec. 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 857 | 763 | 653 | 506 | 477 | 549 | 640 | 640 | 523 | 536 | 679 | 871 |
| Commercial | 511 | 490 | 465 | 413 | 435 | 487 | 522 | 524 | 467 | 456 | 476 | 521 |
| Irrigation | 0 | 0 | 4 | 104 | 287 | 531 | 601 | 475 | 300 | 74 | 2 | 2 |
| Industrial | 288 | 279 | 279 | 272 | 278 | 297 | 290 | 295 | 292 | 297 | 293 | 292 |
| Additional Firm | 179 | 178 | 174 | 171 | 171 | 162 | 173 | 171 | 167 | 170 | 174 | 179 |
| Loss | 161 | 149 | 137 | 164 | 189 | 201 | 223 | 209 | 170 | 146 | 155 | 181 |
| Firm Load | 1,996 | 1,860 | 1,713 | 1,631 | 1,837 | 2,226 | 2,449 | 2,314 | 1,919 | 1,679 | 1,778 | 2,046 |
| Light Load | 1,845 | 1,734 | 1,584 | 1,469 | 1,649 | 2,013 | 2,195 | 2,072 | 1,713 | 1,504 | 1,652 | 1,898 |
| Heavy Load | 2,125 | 1,954 | 1,805 | 1,749 | 1,999 | 2,382 | 2,633 | 2,505 | 2,083 | 1,817 | 1,879 | 2,161 |
| System Load | 1,996 | 1,860 | 1,713 | 1,631 | 1,837 | 2,226 | 2,449 | 2,314 | 1,919 | 1,679 | 1,778 | 2,046 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,996 | 1,860 | 1,713 | 1,631 | 1,837 | 2,226 | 2,449 | 2,314 | 1,919 | 1,679 | 1,778 | 2,046 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2010 | Feb. 2010 | Mar. 2010 | Apr. 2010 | May. 2010 | Jun. 2010 | Jul. 2010 | Aug. 2010 | Sep. 2010 | Oct. 2010 | Nov. 2010 | Dec. 2010 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -25 | -24 | -24 | -24 | -35 | -50 | -61 | -58 | -44 | -30 | -25 | -25 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,674 | 2,546 | 2,469 | 2,039 | 2,912 | 3,364 | 3,446 | 3,164 | 2,842 | 2,171 | 2,506 | 3,059 |
| System Peak (1 Hour) | 2,674 | 2,546 | 2,469 | 2,039 | 2,912 | 3,364 | 3,446 | 3,164 | 2,842 | 2,171 | 2,506 | 3,059 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,674 | 2,546 | 2,469 | 2,039 | 2,912 | 3,364 | 3,446 | 3,164 | 2,842 | 2,171 | 2,506 | 3,059 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2011 | Feb. 2011 | Mar. 2011 | Apr. 2011 | May. 2011 | Jun. 2011 | Jul. 2011 | Aug. 2011 | Sep. 2011 | Oct. 2011 | Nov. 2011 | Dec. 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 869 | 773 | 662 | 512 | 484 | 560 | 655 | 655 | 533 | 546 | 691 | 882 |
| Commercial | 520 | 500 | 475 | 421 | 444 | 498 | 533 | 535 | 477 | 465 | 485 | 529 |
| Irrigation | 0 | 0 | 4 | 104 | 286 | 530 | 600 | 474 | 299 | 74 | 2 | 2 |
| Industrial | 294 | 284 | 284 | 278 | 283 | 302 | 296 | 300 | 298 | 303 | 298 | 297 |
| Additional Firm | 181 | 181 | 176 | 174 | 173 | 164 | 175 | 173 | 169 | 165 | 168 | 173 |
| Loss | 164 | 152 | 139 | 167 | 192 | 204 | 226 | 213 | 173 | 148 | 158 | 183 |
| Firm Load | 2,029 | 1,890 | 1,741 | 1,655 | 1,862 | 2,258 | 2,486 | 2,350 | 1,948 | 1,701 | 1,802 | 2,066 |
| Light Load | 1,876 | 1,762 | 1,611 | 1,491 | 1,672 | 2,041 | 2,227 | 2,104 | 1,739 | 1,524 | 1,674 | 1,918 |
| Heavy Load | 2,161 | 1,985 | 1,835 | 1,775 | 2,026 | 2,416 | 2,708 | 2,528 | 2,115 | 1,841 | 1,904 | 2,174 |
| System Load | 2,029 | 1,890 | 1,741 | 1,655 | 1,862 | 2,258 | 2,486 | 2,350 | 1,948 | 1,701 | 1,802 | 2,066 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,029 | 1,890 | 1,741 | 1,655 | 1,862 | 2,258 | 2,486 | 2,350 | 1,948 | 1,701 | 1,802 | 2,066 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2011 | Feb. 2011 | Mar. 2011 | Apr. 2011 | May. 2011 | Jun. 2011 | Jul. 2011 | Aug. 2011 | Sep. 2011 | Oct. 2011 | Nov. 2011 | Dec. 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -32 | -31 | -30 | -30 | -44 | -62 | -76 | -73 | -56 | -37 | -32 | -31 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,715 | 2,575 | 2,515 | 2,071 | 2,962 | 3,423 | 3,511 | 3,217 | 2,887 | 2,189 | 2,525 | 3,077 |
| System Peak (1 Hour) | 2,715 | 2,575 | 2,515 | 2,071 | 2,962 | 3,423 | 3,511 | 3,217 | 2,887 | 2,189 | 2,525 | 3,077 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,715 | 2,575 | 2,515 | 2,071 | 2,962 | 3,423 | 3,511 | 3,217 | 2,887 | 2,189 | 2,525 | 3,077 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2012 | Feb. 2012 | Mar. 2012 | Apr. 2012 | May. 2012 | Jun. 2012 | Jul. 2012 | Aug. 2012 | Sep. 2012 | Oct. 2012 | Nov. 2012 | Dec. 2012 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 875 | 778 | 666 | 514 | 487 | 567 | 665 | 666 | 539 | 552 | 698 | 890 |
| Commercial | 527 | 507 | 482 | 427 | 451 | 507 | 542 | 543 | 485 | 473 | 492 | 537 |
| Irrigation | 0 | 0 | 4 | 104 | 286 | 529 | 599 | 473 | 299 | 73 | 2 | 2 |
| Industrial | 298 | 288 | 288 | 281 | 287 | 306 | 300 | 305 | 302 | 307 | 302 | 301 |
| Additional Firm | 172 | 170 | 169 | 167 | 167 | 157 | 169 | 166 | 163 | 165 | 168 | 173 |
| Loss | 165 | 153 | 140 | 168 | 193 | 206 | 229 | 215 | 175 | 150 | 159 | 185 |
| Firm Load | 2,038 | 1,895 | 1,749 | 1,662 | 1,871 | 2,272 | 2,504 | 2,368 | 1,961 | 1,720 | 1,821 | 2,089 |
| Light Load | 1,884 | 1,767 | 1,618 | 1,497 | 1,680 | 2,054 | 2,244 | 2,120 | 1,751 | 1,541 | 1,692 | 1,938 |
| Heavy Load | 2,159 | 1,990 | 1,844 | 1,793 | 2,022 | 2,432 | 2,727 | 2,547 | 2,145 | 1,849 | 1,925 | 2,218 |
| System Load | 2,038 | 1,895 | 1,749 | 1,662 | 1,871 | 2,272 | 2,504 | 2,368 | 1,961 | 1,720 | 1,821 | 2,089 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,038 | 1,895 | 1,749 | 1,662 | 1,871 | 2,272 | 2,504 | 2,368 | 1,961 | 1,720 | 1,821 | 2,089 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2012 | Feb. 2012 | Mar. 2012 | Apr. 2012 | May. 2012 | Jun. 2012 | Jul. 2012 | Aug. 2012 | Sep. 2012 | Oct. 2012 | Nov. 2012 | Dec. 2012 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -38 | -37 | -37 | -37 | -54 | -74 | -92 | -89 | -68 | -45 | -39 | -38 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,721 | 2,570 | 2,519 | 2,067 | 3,002 | 3,465 | 3,558 | 3,250 | 2,924 | 2,206 | 2,546 | 3,088 |
| System Peak (1 Hour) | 2,721 | 2,570 | 2,519 | 2,067 | 3,002 | 3,465 | 3,558 | 3,250 | 2,924 | 2,206 | 2,546 | 3,088 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,721 | 2,570 | 2,519 | 2,067 | 3,002 | 3,465 | 3,558 | 3,250 | 2,924 | 2,206 | 2,546 | 3,088 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2013 | Feb. 2013 | Mar. 2013 | Apr. 2013 | May. 2013 | Jun. 2013 | Jul. 2013 | Aug. 2013 | Sep. 2013 | Oct. 2013 | Nov. 2013 | Dec. 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 882 | 782 | 670 | 517 | 491 | 575 | 677 | 676 | 546 | 558 | 705 | 897 |
| Commercial | 535 | 514 | 489 | 434 | 458 | 516 | 551 | 552 | 492 | 480 | 499 | 543 |
| Irrigation | 0 | 0 | 4 | 104 | 285 | 528 | 598 | 473 | 298 | 73 | 2 | 2 |
| Industrial | 303 | 293 | 294 | 287 | 293 | 313 | 306 | 311 | 308 | 313 | 308 | 307 |
| Additional Firm | 172 | 172 | 169 | 167 | 167 | 157 | 169 | 166 | 163 | 165 | 168 | 173 |
| Loss | 167 | 154 | 142 | 170 | 195 | 209 | 232 | 218 | 177 | 152 | 161 | 187 |
| Firm Load | 2,060 | 1,916 | 1,768 | 1,678 | 1,889 | 2,297 | 2,532 | 2,396 | 1,984 | 1,741 | 1,844 | 2,110 |
| Light Load | 1,904 | 1,787 | 1,636 | 1,512 | 1,696 | 2,077 | 2,269 | 2,146 | 1,771 | 1,560 | 1,713 | 1,958 |
| Heavy Load | 2,182 | 2,014 | 1,873 | 1,800 | 2,041 | 2,473 | 2,740 | 2,578 | 2,170 | 1,873 | 1,948 | 2,240 |
| System Load | 2,060 | 1,916 | 1,768 | 1,678 | 1,889 | 2,297 | 2,532 | 2,396 | 1,984 | 1,741 | 1,844 | 2,110 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,060 | 1,916 | 1,768 | 1,678 | 1,889 | 2,297 | 2,532 | 2,396 | 1,984 | 1,741 | 1,844 | 2,110 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2013 | Feb. 2013 | Mar. 2013 | Apr. 2013 | May. 2013 | Jun. 2013 | Jul. 2013 | Aug. 2013 | Sep. 2013 | Oct. 2013 | Nov. 2013 | Dec. 2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -45 | -44 | -43 | -43 | -63 | -87 | -107 | -104 | -79 | -53 | -45 | -44 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,737 | 2,583 | 2,534 | 2,069 | 3,050 | 3,521 | 3,617 | 3,302 | 2,968 | 2,227 | 2,569 | 3,120 |
| System Peak (1 Hour) | 2,737 | 2,583 | 2,534 | 2,069 | 3,050 | 3,521 | 3,617 | 3,302 | 2,968 | 2,227 | 2,569 | 3,120 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,737 | 2,583 | 2,534 | 2,069 | 3,050 | 3,521 | 3,617 | 3,302 | 2,968 | 2,227 | 2,569 | 3,120 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2014 | Feb. 2014 | Mar. 2014 | Apr. 2014 | May. 2014 | Jun. 2014 | Jul. 2014 | Aug. 2014 | Sep. 2014 | Oct. 2014 | Nov. 2014 | Dec. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 886 | 784 | 672 | 518 | 492 | 580 | 686 | 685 | 551 | 562 | 710 | 903 |
| Commercial | 540 | 519 | 495 | 438 | 464 | 523 | 558 | 559 | 498 | 486 | 504 | 548 |
| Irrigation | 0 | 0 | 4 | 104 | 284 | 525 | 595 | 470 | 297 | 72 | 2 | 2 |
| Industrial | 307 | 297 | 297 | 290 | 297 | 317 | 309 | 315 | 312 | 317 | 312 | 311 |
| Additional Firm | 172 | 172 | 168 | 166 | 166 | 157 | 169 | 166 | 163 | 165 | 168 | 173 |
| Loss | 168 | 155 | 143 | 171 | 197 | 210 | 234 | 220 | 178 | 153 | 163 | 189 |
| Firm Load | 2,073 | 1,928 | 1,780 | 1,688 | 1,900 | 2,313 | 2,551 | 2,416 | 1,999 | 1,756 | 1,859 | 2,125 |
| Light Load | 1,916 | 1,797 | 1,647 | 1,521 | 1,705 | 2,091 | 2,286 | 2,163 | 1,784 | 1,573 | 1,727 | 1,972 |
| Heavy Load | 2,196 | 2,025 | 1,885 | 1,810 | 2,053 | 2,490 | 2,760 | 2,615 | 2,170 | 1,888 | 1,974 | 2,245 |
| System Load | 2,073 | 1,928 | 1,780 | 1,688 | 1,900 | 2,313 | 2,551 | 2,416 | 1,999 | 1,756 | 1,859 | 2,125 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,073 | 1,928 | 1,780 | 1,688 | 1,900 | 2,313 | 2,551 | 2,416 | 1,999 | 1,756 | 1,859 | 2,125 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2014 | Feb. 2014 | Mar. 2014 | Apr. 2014 | May. 2014 | Jun. 2014 | Jul. 2014 | Aug. 2014 | Sep. 2014 | Oct. 2014 | Nov. 2014 | Dec. 2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -52 | -51 | -49 | -50 | -71 | -98 | -123 | -118 | -91 | -60 | -52 | -51 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,751 | 2,590 | 2,548 | 2,076 | 3,095 | 3,551 | 3,666 | 3,310 | 3,012 | 2,240 | 2,584 | 3,050 |
| System Peak (1 Hour) | 2,751 | 2,590 | 2,548 | 2,076 | 3,095 | 3,551 | 3,666 | 3,310 | 3,012 | 2,240 | 2,584 | 3,050 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,751 | 2,590 | 2,548 | 2,076 | 3,095 | 3,551 | 3,666 | 3,310 | 3,012 | 2,240 | 2,584 | 3,050 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2015 | Feb. 2015 | Mar. 2015 | Apr. 2015 | May. 2015 | Jun. 2015 | Jul. 2015 | Aug. 2015 | Sep. 2015 | Oct. 2015 | Nov. 2015 | Dec. 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 889 | 786 | 674 | 519 | 494 | 587 | 695 | 695 | 557 | 567 | 715 | 913 |
| Commercial | 545 | 524 | 500 | 443 | 470 | 530 | 566 | 566 | 504 | 492 | 509 | 555 |
| Irrigation | 0 | 0 | 4 | 104 | 284 | 526 | 596 | 471 | 297 | 72 | 2 | 2 |
| Industrial | 313 | 302 | 303 | 295 | 302 | 322 | 315 | 321 | 317 | 323 | 318 | 317 |
| Additional Firm | 172 | 172 | 168 | 166 | 166 | 157 | 169 | 166 | 163 | 165 | 168 | 173 |
| Loss | 169 | 156 | 144 | 172 | 198 | 212 | 236 | 223 | 180 | 155 | 164 | 191 |
| Firm Load | 2,088 | 1,941 | 1,794 | 1,700 | 1,915 | 2,335 | 2,577 | 2,442 | 2,018 | 1,774 | 1,876 | 2,151 |
| Light Load | 1,930 | 1,810 | 1,660 | 1,531 | 1,719 | 2,111 | 2,310 | 2,186 | 1,802 | 1,589 | 1,743 | 1,997 |
| Heavy Load | 2,212 | 2,039 | 1,900 | 1,823 | 2,083 | 2,498 | 2,788 | 2,643 | 2,191 | 1,907 | 1,993 | 2,273 |
| System Load | 2,088 | 1,941 | 1,794 | 1,700 | 1,915 | 2,335 | 2,577 | 2,442 | 2,018 | 1,774 | 1,876 | 2,151 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,088 | 1,941 | 1,794 | 1,700 | 1,915 | 2,335 | 2,577 | 2,442 | 2,018 | 1,774 | 1,876 | 2,151 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2015 | Feb. 2015 | Mar. 2015 | Apr. 2015 | May. 2015 | Jun. 2015 | Jul. 2015 | Aug. 2015 | Sep. 2015 | Oct. 2015 | Nov. 2015 | Dec. 2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -58 | -57 | -55 | -56 | -78 | -108 | -135 | -130 | -100 | -66 | -58 | -57 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,743 | 2,583 | 2,523 | 2,043 | 3,144 | 3,610 | 3,723 | 3,366 | 3,058 | 2,256 | 2,603 | 3,102 |
| System Peak (1 Hour) | 2,743 | 2,583 | 2,523 | 2,043 | 3,144 | 3,610 | 3,723 | 3,366 | 3,058 | 2,256 | 2,603 | 3,102 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,743 | 2,583 | 2,523 | 2,043 | 3,144 | 3,610 | 3,723 | 3,366 | 3,058 | 2,256 | 2,603 | 3,102 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2016 | Feb. 2016 | Mar. 2016 | Apr. 2016 | May. 2016 | Jun. 2016 | Jul. 2016 | Aug. 2016 | Sep. 2016 | Oct. 2016 | Nov. 2016 | Dec. 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 901 | 796 | 683 | 525 | 501 | 599 | 712 | 713 | 568 | 577 | 727 | 923 |
| Commercial | 555 | 534 | 510 | 452 | 479 | 542 | 579 | 577 | 515 | 502 | 518 | 562 |
| Irrigation | 0 | 0 | 4 | 104 | 285 | 527 | 597 | 472 | 298 | 73 | 2 | 2 |
| Industrial | 317 | 307 | 307 | 300 | 307 | 327 | 320 | 326 | 322 | 328 | 322 | 322 |
| Additional Firm | 172 | 170 | 168 | 166 | 166 | 157 | 169 | 166 | 163 | 165 | 168 | 173 |
| Loss | 172 | 158 | 146 | 174 | 201 | 216 | 240 | 227 | 183 | 158 | 167 | 193 |
| Firm Load | 2,117 | 1,965 | 1,819 | 1,721 | 1,939 | 2,368 | 2,617 | 2,481 | 2,049 | 1,802 | 1,905 | 2,175 |
| Light Load | 1,957 | 1,832 | 1,683 | 1,551 | 1,741 | 2,141 | 2,345 | 2,221 | 1,829 | 1,614 | 1,770 | 2,019 |
| Heavy Load | 2,255 | 2,063 | 1,917 | 1,846 | 2,110 | 2,534 | 2,851 | 2,668 | 2,225 | 1,950 | 2,013 | 2,288 |
| System Load | 2,117 | 1,965 | 1,819 | 1,721 | 1,939 | 2,368 | 2,617 | 2,481 | 2,049 | 1,802 | 1,905 | 2,175 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,117 | 1,965 | 1,819 | 1,721 | 1,939 | 2,368 | 2,617 | 2,481 | 2,049 | 1,802 | 1,905 | 2,175 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2016 | Feb. 2016 | Mar. 2016 | Apr. 2016 | May. 2016 | Jun. 2016 | Jul. 2016 | Aug. 2016 | Sep. 2016 | Oct. 2016 | Nov. 2016 | Dec. 2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -64 | -62 | -61 | -61 | -85 | -117 | -146 | -142 | -109 | -72 | -64 | -63 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,777 | 2,598 | 2,559 | 2,066 | 3,195 | 3,676 | 3,793 | 3,432 | 3,104 | 2,283 | 2,632 | 3,149 |
| System Peak (1 Hour) | 2,777 | 2,598 | 2,559 | 2,066 | 3,195 | 3,676 | 3,793 | 3,432 | 3,104 | 2,283 | 2,632 | 3,149 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,777 | 2,598 | 2,559 | 2,066 | 3,195 | 3,676 | 3,793 | 3,432 | 3,104 | 2,283 | 2,632 | 3,149 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2017 | Feb. 2017 | Mar. 2017 | Apr. 2017 | May. 2017 | Jun. 2017 | Jul. 2017 | Aug. 2017 | Sep. 2017 | Oct. 2017 | Nov. 2017 | Dec. 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 905 | 798 | 685 | 526 | 503 | 606 | 723 | 723 | 574 | 582 | 732 | 929 |
| Commercial | 559 | 538 | 515 | 456 | 484 | 549 | 586 | 584 | 521 | 507 | 523 | 566 |
| Irrigation | 0 | 0 | 4 | 104 | 284 | 525 | 595 | 471 | 297 | 72 | 2 | 2 |
| Industrial | 321 | 311 | 311 | 304 | 311 | 331 | 324 | 330 | 326 | 332 | 327 | 326 |
| Additional Firm | 171 | 171 | 168 | 166 | 166 | 157 | 168 | 166 | 162 | 164 | 168 | 172 |
| Loss | 173 | 159 | 147 | 175 | 202 | 217 | 243 | 229 | 185 | 159 | 169 | 195 |
| Firm Load | 2,130 | 1,977 | 1,830 | 1,731 | 1,950 | 2,385 | 2,639 | 2,502 | 2,065 | 1,817 | 1,920 | 2,190 |
| Light Load | 1,969 | 1,844 | 1,693 | 1,560 | 1,751 | 2,157 | 2,365 | 2,240 | 1,844 | 1,628 | 1,784 | 2,032 |
| Heavy Load | 2,257 | 2,078 | 1,929 | 1,868 | 2,108 | 2,553 | 2,875 | 2,691 | 2,242 | 1,967 | 2,029 | 2,325 |
| System Load | 2,130 | 1,977 | 1,830 | 1,731 | 1,950 | 2,385 | 2,639 | 2,502 | 2,065 | 1,817 | 1,920 | 2,190 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,130 | 1,977 | 1,830 | 1,731 | 1,950 | 2,385 | 2,639 | 2,502 | 2,065 | 1,817 | 1,920 | 2,190 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2017 | Feb. 2017 | Mar. 2017 | Apr. 2017 | May. 2017 | Jun. 2017 | Jul. 2017 | Aug. 2017 | Sep. 2017 | Oct. 2017 | Nov. 2017 | Dec. 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -70 | -68 | -67 | -67 | -92 | -126 | -157 | -154 | -119 | -79 | -70 | -69 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,794 | 2,615 | 2,577 | 2,079 | 3,242 | 3,701 | 3,846 | 3,429 | 3,150 | 2,297 | 2,648 | 3,047 |
| System Peak (1 Hour) | 2,794 | 2,615 | 2,577 | 2,079 | 3,242 | 3,701 | 3,846 | 3,429 | 3,150 | 2,297 | 2,648 | 3,047 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,794 | 2,615 | 2,577 | 2,079 | 3,242 | 3,701 | 3,846 | 3,429 | 3,150 | 2,297 | 2,648 | 3,047 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2018 | Feb. 2018 | Mar. 2018 | Apr. 2018 | May. 2018 | Jun. 2018 | Jul. 2018 | Aug. 2018 | Sep. 2018 | Oct. 2018 | Nov. 2018 | Dec. 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 909 | 800 | 687 | 527 | 506 | 613 | 734 | 734 | 580 | 587 | 738 | 939 |
| Commercial | 562 | 541 | 518 | 459 | 488 | 555 | 591 | 589 | 525 | 511 | 526 | 573 |
| Irrigation | 0 | 0 | 4 | 104 | 284 | 526 | 596 | 471 | 297 | 72 | 2 | 2 |
| Industrial | 327 | 316 | 317 | 309 | 316 | 337 | 329 | 336 | 332 | 337 | 332 | 332 |
| Additional Firm | 171 | 171 | 168 | 166 | 166 | 157 | 168 | 166 | 162 | 164 | 168 | 172 |
| Loss | 174 | 160 | 148 | 176 | 204 | 219 | 245 | 231 | 186 | 161 | 170 | 197 |
| Firm Load | 2,143 | 1,988 | 1,842 | 1,741 | 1,963 | 2,407 | 2,664 | 2,527 | 2,084 | 1,833 | 1,936 | 2,214 |
| Light Load | 1,981 | 1,854 | 1,704 | 1,569 | 1,762 | 2,176 | 2,388 | 2,262 | 1,860 | 1,642 | 1,798 | 2,055 |
| Heavy Load | 2,271 | 2,089 | 1,941 | 1,879 | 2,122 | 2,575 | 2,902 | 2,718 | 2,279 | 1,971 | 2,045 | 2,351 |
| System Load | 2,143 | 1,988 | 1,842 | 1,741 | 1,963 | 2,407 | 2,664 | 2,527 | 2,084 | 1,833 | 1,936 | 2,214 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,143 | 1,988 | 1,842 | 1,741 | 1,963 | 2,407 | 2,664 | 2,527 | 2,084 | 1,833 | 1,936 | 2,214 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2018 | Feb. 2018 | Mar. 2018 | Apr. 2018 | May. 2018 | Jun. 2018 | Jul. 2018 | Aug. 2018 | Sep. 2018 | Oct. 2018 | Nov. 2018 | Dec. 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -76 | -74 | -72 | -72 | -99 | -134 | -168 | -165 | -127 | -85 | -75 | -74 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,775 | 2,599 | 2,532 | 2,031 | 3,290 | 3,757 | 3,901 | 3,481 | 3,197 | 2,312 | 2,664 | 3,087 |
| System Peak (1 Hour) | 2,775 | 2,599 | 2,532 | 2,031 | 3,290 | 3,757 | 3,901 | 3,481 | 3,197 | 2,312 | 2,664 | 3,087 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,775 | 2,599 | 2,532 | 2,031 | 3,290 | 3,757 | 3,901 | 3,481 | 3,197 | 2,312 | 2,664 | 3,087 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2019 | Feb. 2019 | Mar. 2019 | Apr. 2019 | May. 2019 | Jun. 2019 | Jul. 2019 | Aug. 2019 | Sep. 2019 | Oct. 2019 | Nov. 2019 | Dec. 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 920 | 808 | 694 | 531 | 512 | 625 | 751 | 751 | 592 | 597 | 749 | 953 |
| Commercial | 572 | 551 | 528 | 468 | 498 | 568 | 604 | 602 | 536 | 521 | 536 | 583 |
| Irrigation | 0 | 0 | 4 | 104 | 284 | 527 | 597 | 472 | 298 | 73 | 2 | 2 |
| Industrial | 332 | 321 | 322 | 314 | 321 | 343 | 335 | 342 | 337 | 343 | 338 | 337 |
| Additional Firm | 171 | 171 | 168 | 166 | 166 | 157 | 168 | 166 | 162 | 164 | 168 | 172 |
| Loss | 176 | 162 | 150 | 178 | 207 | 222 | 249 | 235 | 189 | 163 | 173 | 200 |
| Firm Load | 2,171 | 2,013 | 1,867 | 1,762 | 1,988 | 2,441 | 2,705 | 2,567 | 2,115 | 1,861 | 1,964 | 2,247 |
| Light Load | 2,007 | 1,877 | 1,727 | 1,588 | 1,784 | 2,207 | 2,424 | 2,298 | 1,888 | 1,667 | 1,825 | 2,086 |
| Heavy Load | 2,300 | 2,115 | 1,977 | 1,889 | 2,148 | 2,628 | 2,926 | 2,761 | 2,313 | 2,001 | 2,076 | 2,386 |
| System Load | 2,171 | 2,013 | 1,867 | 1,762 | 1,988 | 2,441 | 2,705 | 2,567 | 2,115 | 1,861 | 1,964 | 2,247 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,171 | 2,013 | 1,867 | 1,762 | 1,988 | 2,441 | 2,705 | 2,567 | 2,115 | 1,861 | 1,964 | 2,247 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2019 | Feb. 2019 | Mar. 2019 | Apr. 2019 | May. 2019 | Jun. 2019 | Jul. 2019 | Aug. 2019 | Sep. 2019 | Oct. 2019 | Nov. 2019 | Dec. 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -82 | -79 | -78 | -78 | -106 | -142 | -179 | -175 | -136 | -91 | -81 | -80 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,805 | 2,619 | 2,563 | 2,049 | 3,342 | 3,825 | 3,972 | 3,549 | 3,244 | 2,338 | 2,694 | 3,149 |
| System Peak (1 Hour) | 2,805 | 2,619 | 2,563 | 2,049 | 3,342 | 3,825 | 3,972 | 3,549 | 3,244 | 2,338 | 2,694 | 3,149 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,805 | 2,619 | 2,563 | 2,049 | 3,342 | 3,825 | 3,972 | 3,549 | 3,244 | 2,338 | 2,694 | 3,149 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2020 | Feb. 2020 | Mar. 2020 | Apr. 2020 | May. 2020 | Jun. 2020 | Jul. 2020 | Aug. 2020 | Sep. 2020 | Oct. 2020 | Nov. 2020 | Dec. 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 932 | 817 | 703 | 538 | 519 | 639 | 770 | 770 | 605 | 608 | 761 | 969 |
| Commercial | 583 | 561 | 539 | 478 | 510 | 581 | 619 | 617 | 548 | 533 | 547 | 594 |
| Irrigation | 0 | 0 | 4 | 104 | 285 | 528 | 598 | 473 | 298 | 73 | 2 | 2 |
| Industrial | 337 | 326 | 327 | 319 | 327 | 348 | 341 | 348 | 343 | 349 | 344 | 343 |
| Additional Firm | 171 | 169 | 168 | 166 | 166 | 157 | 168 | 166 | 162 | 164 | 168 | 172 |
| Loss | 179 | 165 | 152 | 181 | 210 | 226 | 253 | 239 | 193 | 166 | 175 | 203 |
| Firm Load | 2,202 | 2,039 | 1,894 | 1,786 | 2,016 | 2,478 | 2,749 | 2,612 | 2,149 | 1,892 | 1,996 | 2,282 |
| Light Load | 2,036 | 1,901 | 1,752 | 1,609 | 1,809 | 2,241 | 2,464 | 2,339 | 1,918 | 1,695 | 1,855 | 2,118 |
| Heavy Load | 2,333 | 2,141 | 2,006 | 1,915 | 2,193 | 2,652 | 2,975 | 2,827 | 2,333 | 2,035 | 2,120 | 2,412 |
| System Load | 2,202 | 2,039 | 1,894 | 1,786 | 2,016 | 2,478 | 2,749 | 2,612 | 2,149 | 1,892 | 1,996 | 2,282 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,202 | 2,039 | 1,894 | 1,786 | 2,016 | 2,478 | 2,749 | 2,612 | 2,149 | 1,892 | 1,996 | 2,282 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2020 | Feb. 2020 | Mar. 2020 | Apr. 2020 | May. 2020 | Jun. 2020 | Jul. 2020 | Aug. 2020 | Sep. 2020 | Oct. 2020 | Nov. 2020 | Dec. 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -87 | -84 | -83 | -83 | -111 | -150 | -190 | -185 | -144 | -96 | -86 | -85 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,842 | 2,643 | 2,602 | 2,074 | 3,395 | 3,895 | 4,047 | 3,622 | 3,291 | 2,368 | 2,727 | 3,216 |
| System Peak (1 Hour) | 2,842 | 2,643 | 2,602 | 2,074 | 3,395 | 3,895 | 4,047 | 3,622 | 3,291 | 2,368 | 2,727 | 3,216 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,842 | 2,643 | 2,602 | 2,074 | 3,395 | 3,895 | 4,047 | 3,622 | 3,291 | 2,368 | 2,727 | 3,216 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2021 | Feb. 2021 | Mar. 2021 | Apr. 2021 | May. 2021 | Jun. 2021 | Jul. 2021 | Aug. 2021 | Sep. 2021 | Oct. 2021 | Nov. 2021 | Dec. 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 945 | 827 | 712 | 544 | 527 | 653 | 790 | 790 | 618 | 619 | 774 | 984 |
| Commercial | 594 | 572 | 550 | 488 | 521 | 595 | 634 | 631 | 561 | 545 | 557 | 605 |
| Irrigation | 0 | 0 | 4 | 105 | 285 | 528 | 599 | 474 | 299 | 73 | 2 | 2 |
| Industrial | 344 | 333 | 334 | 325 | 333 | 355 | 347 | 355 | 350 | 356 | 350 | 350 |
| Additional Firm | 170 | 171 | 167 | 165 | 165 | 156 | 168 | 165 | 162 | 164 | 167 | 171 |
| Loss | 181 | 167 | 154 | 184 | 213 | 230 | 258 | 244 | 196 | 169 | 178 | 207 |
| Firm Load | 2,235 | 2,070 | 1,922 | 1,810 | 2,044 | 2,517 | 2,796 | 2,658 | 2,185 | 1,925 | 2,029 | 2,318 |
| Light Load | 2,066 | 1,930 | 1,778 | 1,631 | 1,835 | 2,276 | 2,506 | 2,380 | 1,951 | 1,724 | 1,885 | 2,152 |
| Heavy Load | 2,380 | 2,175 | 2,026 | 1,941 | 2,224 | 2,694 | 3,006 | 2,877 | 2,372 | 2,083 | 2,144 | 2,450 |
| System Load | 2,235 | 2,070 | 1,922 | 1,810 | 2,044 | 2,517 | 2,796 | 2,658 | 2,185 | 1,925 | 2,029 | 2,318 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,235 | 2,070 | 1,922 | 1,810 | 2,044 | 2,517 | 2,796 | 2,658 | 2,185 | 1,925 | 2,029 | 2,318 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2021 | Feb. 2021 | Mar. 2021 | Apr. 2021 | May. 2021 | Jun. 2021 | Jul. 2021 | Aug. 2021 | Sep. 2021 | Oct. 2021 | Nov. 2021 | Dec. 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -92 | -90 | -88 | -88 | -117 | -159 | -200 | -195 | -152 | -102 | -92 | -91 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,881 | 2,670 | 2,644 | 2,100 | 3,449 | 3,966 | 4,124 | 3,695 | 3,338 | 2,398 | 2,761 | 3,284 |
| System Peak (1 Hour) | 2,881 | 2,670 | 2,644 | 2,100 | 3,449 | 3,966 | 4,124 | 3,695 | 3,338 | 2,398 | 2,761 | 3,284 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,881 | 2,670 | 2,644 | 2,100 | 3,449 | 3,966 | 4,124 | 3,695 | 3,338 | 2,398 | 2,761 | 3,284 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2022 | Feb. 2022 | Mar. 2022 | Apr. 2022 | May. 2022 | Jun. 2022 | Jul. 2022 | Aug. 2022 | Sep. 2022 | Oct. 2022 | Nov. 2022 | Dec. 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 958 | 837 | 721 | 550 | 534 | 667 | 810 | 811 | 631 | 630 | 788 | 1,000 |
| Commercial | 605 | 583 | 562 | 498 | 533 | 610 | 651 | 646 | 574 | 557 | 568 | 616 |
| Irrigation | 0 | 0 | 5 | 105 | 286 | 529 | 601 | 475 | 299 | 73 | 2 | 2 |
| Industrial | 350 | 338 | 339 | 331 | 339 | 361 | 354 | 361 | 355 | 362 | 356 | 356 |
| Additional Firm | 170 | 171 | 167 | 165 | 165 | 156 | 168 | 165 | 162 | 164 | 167 | 171 |
| Loss | 184 | 169 | 157 | 186 | 216 | 233 | 262 | 248 | 199 | 172 | 182 | 210 |
| Firm Load | 2,268 | 2,099 | 1,950 | 1,835 | 2,073 | 2,557 | 2,845 | 2,705 | 2,221 | 1,958 | 2,063 | 2,355 |
| Light Load | 2,096 | 1,957 | 1,804 | 1,653 | 1,861 | 2,312 | 2,549 | 2,422 | 1,983 | 1,754 | 1,916 | 2,186 |
| Heavy Load | 2,415 | 2,205 | 2,056 | 1,967 | 2,255 | 2,736 | 3,099 | 2,909 | 2,412 | 2,119 | 2,179 | 2,477 |
| System Load | 2,268 | 2,099 | 1,950 | 1,835 | 2,073 | 2,557 | 2,845 | 2,705 | 2,221 | 1,958 | 2,063 | 2,355 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,268 | 2,099 | 1,950 | 1,835 | 2,073 | 2,557 | 2,845 | 2,705 | 2,221 | 1,958 | 2,063 | 2,355 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2022 | Feb. 2022 | Mar. 2022 | Apr. 2022 | May. 2022 | Jun. 2022 | Jul. 2022 | Aug. 2022 | Sep. 2022 | Oct. 2022 | Nov. 2022 | Dec. 2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -97 | -95 | -94 | -93 | -123 | -167 | -210 | -206 | -160 | -107 | -97 | -96 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,920 | 2,696 | 2,686 | 2,127 | 3,502 | 4,037 | 4,202 | 3,768 | 3,385 | 2,430 | 2,796 | 3,351 |
| System Peak (1 Hour) | 2,920 | 2,696 | 2,686 | 2,127 | 3,502 | 4,037 | 4,202 | 3,768 | 3,385 | 2,430 | 2,796 | 3,351 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,920 | 2,696 | 2,686 | 2,127 | 3,502 | 4,037 | 4,202 | 3,768 | 3,385 | 2,430 | 2,796 | 3,351 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2023 | Feb. 2023 | Mar. 2023 | Apr. 2023 | May. 2023 | Jun. 2023 | Jul. 2023 | Aug. 2023 | Sep. 2023 | Oct. 2023 | Nov. 2023 | Dec. 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 970 | 847 | 730 | 556 | 542 | 681 | 830 | 831 | 644 | 641 | 801 | 1,015 |
| Commercial | 617 | 594 | 573 | 509 | 545 | 626 | 667 | 661 | 588 | 570 | 580 | 628 |
| Irrigation | 0 | 0 | 5 | 105 | 286 | 530 | 602 | 475 | 300 | 73 | 2 | 2 |
| Industrial | 356 | 344 | 345 | 337 | 345 | 368 | 360 | 367 | 362 | 368 | 362 | 362 |
| Additional Firm | 169 | 169 | 166 | 164 | 164 | 155 | 167 | 164 | 161 | 163 | 166 | 170 |
| Loss | 187 | 172 | 159 | 189 | 219 | 237 | 267 | 253 | 203 | 175 | 185 | 213 |
| Firm Load | 2,299 | 2,126 | 1,978 | 1,859 | 2,100 | 2,596 | 2,892 | 2,752 | 2,257 | 1,990 | 2,095 | 2,391 |
| Light Load | 2,125 | 1,983 | 1,830 | 1,675 | 1,885 | 2,347 | 2,592 | 2,464 | 2,015 | 1,782 | 1,947 | 2,219 |
| Heavy Load | 2,436 | 2,234 | 2,085 | 2,006 | 2,270 | 2,778 | 3,151 | 2,960 | 2,451 | 2,153 | 2,214 | 2,538 |
| System Load | 2,299 | 2,126 | 1,978 | 1,859 | 2,100 | 2,596 | 2,892 | 2,752 | 2,257 | 1,990 | 2,095 | 2,391 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,299 | 2,126 | 1,978 | 1,859 | 2,100 | 2,596 | 2,892 | 2,752 | 2,257 | 1,990 | 2,095 | 2,391 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2023 | Feb. 2023 | Mar. 2023 | Apr. 2023 | May. 2023 | Jun. 2023 | Jul. 2023 | Aug. 2023 | Sep. 2023 | Oct. 2023 | Nov. 2023 | Dec. 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -103 | -100 | -99 | -98 | -130 | -174 | -219 | -216 | -169 | -112 | -102 | -101 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,957 | 2,720 | 2,726 | 2,153 | 3,555 | 4,108 | 4,280 | 3,841 | 3,432 | 2,460 | 2,830 | 3,417 |
| System Peak (1 Hour) | 2,957 | 2,720 | 2,726 | 2,153 | 3,555 | 4,108 | 4,280 | 3,841 | 3,432 | 2,460 | 2,830 | 3,417 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,957 | 2,720 | 2,726 | 2,153 | 3,555 | 4,108 | 4,280 | 3,841 | 3,432 | 2,460 | 2,830 | 3,417 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2024 | Feb. 2024 | Mar. 2024 | Apr. 2024 | May. 2024 | Jun. 2024 | Jul. 2024 | Aug. 2024 | Sep. 2024 | Oct. 2024 | Nov. 2024 | Dec. 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 983 | 856 | 738 | 562 | 549 | 695 | 852 | 852 | 657 | 653 | 814 | 1,031 |
| Commercial | 628 | 606 | 586 | 519 | 557 | 642 | 684 | 678 | 602 | 582 | 592 | 640 |
| Irrigation | 0 | 0 | 5 | 105 | 287 | 531 | 603 | 476 | 301 | 73 | 2 | 2 |
| Industrial | 361 | 349 | 351 | 342 | 350 | 374 | 365 | 373 | 367 | 373 | 368 | 368 |
| Additional Firm | 169 | 167 | 166 | 164 | 164 | 155 | 167 | 164 | 161 | 163 | 166 | 170 |
| Loss | 189 | 174 | 161 | 191 | 222 | 241 | 271 | 257 | 206 | 178 | 188 | 217 |
| Firm Load | 2,331 | 2,153 | 2,007 | 1,883 | 2,129 | 2,637 | 2,941 | 2,800 | 2,294 | 2,022 | 2,128 | 2,427 |
| Light Load | 2,155 | 2,007 | 1,857 | 1,697 | 1,911 | 2,385 | 2,636 | 2,507 | 2,048 | 1,811 | 1,977 | 2,253 |
| Heavy Load | 2,470 | 2,260 | 2,125 | 2,019 | 2,300 | 2,840 | 3,182 | 3,012 | 2,509 | 2,174 | 2,249 | 2,577 |
| System Load | 2,331 | 2,153 | 2,007 | 1,883 | 2,129 | 2,637 | 2,941 | 2,800 | 2,294 | 2,022 | 2,128 | 2,427 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,331 | 2,153 | 2,007 | 1,883 | 2,129 | 2,637 | 2,941 | 2,800 | 2,294 | 2,022 | 2,128 | 2,427 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2024 | Feb. 2024 | Mar. 2024 | Apr. 2024 | May. 2024 | Jun. 2024 | Jul. 2024 | Aug. 2024 | Sep. 2024 | Oct. 2024 | Nov. 2024 | Dec. 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -108 | -105 | -102 | -102 | -135 | -181 | -229 | -225 | -176 | -118 | -106 | -105 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 2,994 | 2,745 | 2,768 | 2,178 | 3,608 | 4,181 | 4,359 | 3,916 | 3,481 | 2,490 | 2,865 | 3,483 |
| System Peak (1 Hour) | 2,994 | 2,745 | 2,768 | 2,178 | 3,608 | 4,181 | 4,359 | 3,916 | 3,481 | 2,490 | 2,865 | 3,483 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 2,994 | 2,745 | 2,768 | 2,178 | 3,608 | 4,181 | 4,359 | 3,916 | 3,481 | 2,490 | 2,865 | 3,483 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2025 | Feb. 2025 | Mar. 2025 | Apr. 2025 | May. 2025 | Jun. 2025 | Jul. 2025 | Aug. 2025 | Sep. 2025 | Oct. 2025 | Nov. 2025 | Dec. 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 996 | 866 | 747 | 568 | 557 | 710 | 873 | 872 | 672 | 664 | 827 | 1,047 |
| Commercial | 640 | 618 | 598 | 530 | 570 | 658 | 701 | 696 | 616 | 595 | 604 | 652 |
| Irrigation | 0 | 0 | 5 | 105 | 287 | 532 | 604 | 477 | 301 | 73 | 2 | 2 |
| Industrial | 368 | 356 | 358 | 348 | 357 | 381 | 372 | 381 | 375 | 381 | 376 | 375 |
| Additional Firm | 167 | 168 | 165 | 163 | 163 | 154 | 166 | 163 | 160 | 162 | 164 | 168 |
| Loss | 192 | 176 | 164 | 194 | 225 | 245 | 276 | 262 | 210 | 181 | 191 | 220 |
| Firm Load | 2,363 | 2,184 | 2,036 | 1,908 | 2,159 | 2,680 | 2,992 | 2,851 | 2,333 | 2,056 | 2,163 | 2,464 |
| Light Load | 2,185 | 2,036 | 1,884 | 1,720 | 1,938 | 2,423 | 2,681 | 2,553 | 2,083 | 1,842 | 2,010 | 2,287 |
| Heavy Load | 2,504 | 2,295 | 2,156 | 2,047 | 2,333 | 2,885 | 3,237 | 3,086 | 2,533 | 2,211 | 2,297 | 2,604 |
| System Load | 2,363 | 2,184 | 2,036 | 1,908 | 2,159 | 2,680 | 2,992 | 2,851 | 2,333 | 2,056 | 2,163 | 2,464 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,363 | 2,184 | 2,036 | 1,908 | 2,159 | 2,680 | 2,992 | 2,851 | 2,333 | 2,056 | 2,163 | 2,464 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2025 | Feb. 2025 | Mar. 2025 | Apr. 2025 | May. 2025 | Jun. 2025 | Jul. 2025 | Aug. 2025 | Sep. 2025 | Oct. 2025 | Nov. 2025 | Dec. 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -113 | -110 | -107 | -107 | -141 | -188 | -239 | -234 | -184 | -123 | -111 | -111 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 3,033 | 2,772 | 2,811 | 2,204 | 3,663 | 4,254 | 4,440 | 3,993 | 3,527 | 2,523 | 2,902 | 3,552 |
| System Peak (1 Hour) | 3,033 | 2,772 | 2,811 | 2,204 | 3,663 | 4,254 | 4,440 | 3,993 | 3,527 | 2,523 | 2,902 | 3,552 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 3,033 | 2,772 | 2,811 | 2,204 | 3,663 | 4,254 | 4,440 | 3,993 | 3,527 | 2,523 | 2,902 | 3,552 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2026 | Feb. 2026 | Mar. 2026 | Apr. 2026 | May. 2026 | Jun. 2026 | Jul. 2026 | Aug. 2026 | Sep. 2026 | Oct. 2026 | Nov. 2026 | Dec. 2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 1,009 | 876 | 756 | 574 | 565 | 726 | 897 | 896 | 687 | 676 | 841 | 1,063 |
| Commercial | 652 | 630 | 611 | 542 | 583 | 675 | 719 | 713 | 631 | 609 | 616 | 664 |
| Irrigation | 0 | 0 | 5 | 105 | 288 | 533 | 605 | 478 | 302 | 73 | 2 | 2 |
| Industrial | 378 | 365 | 367 | 357 | 366 | 391 | 382 | 391 | 384 | 391 | 385 | 385 |
| Additional Firm | 166 | 166 | 163 | 162 | 162 | 153 | 164 | 162 | 159 | 160 | 163 | 167 |
| Loss | 195 | 179 | 166 | 197 | 229 | 249 | 281 | 267 | 214 | 184 | 194 | 224 |
| Firm Load | 2,400 | 2,216 | 2,068 | 1,937 | 2,193 | 2,727 | 3,049 | 2,907 | 2,376 | 2,094 | 2,201 | 2,504 |
| Light Load | 2,219 | 2,066 | 1,914 | 1,745 | 1,968 | 2,465 | 2,732 | 2,603 | 2,121 | 1,876 | 2,045 | 2,324 |
| Heavy Load | 2,543 | 2,329 | 2,190 | 2,077 | 2,385 | 2,918 | 3,298 | 3,147 | 2,580 | 2,252 | 2,337 | 2,646 |
| System Load | 2,400 | 2,216 | 2,068 | 1,937 | 2,193 | 2,727 | 3,049 | 2,907 | 2,376 | 2,094 | 2,201 | 2,504 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,400 | 2,216 | 2,068 | 1,937 | 2,193 | 2,727 | 3,049 | 2,907 | 2,376 | 2,094 | 2,201 | 2,504 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2026 | Feb. 2026 | Mar. 2026 | Apr. 2026 | May. 2026 | Jun. 2026 | Jul. 2026 | Aug. 2026 | Sep. 2026 | Oct. 2026 | Nov. 2026 | Dec. 2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -114 | -111 | -108 | -108 | -142 | -191 | -243 | -238 | -187 | -124 | -112 | -112 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 3,075 | 2,802 | 2,857 | 2,234 | 3,721 | 4,332 | 4,527 | 4,075 | 3,579 | 2,559 | 2,942 | 3,622 |
| System Peak (1 Hour) | 3,075 | 2,802 | 2,857 | 2,234 | 3,721 | 4,332 | 4,527 | 4,075 | 3,579 | 2,559 | 2,942 | 3,622 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 3,075 | 2,802 | 2,857 | 2,234 | 3,721 | 4,332 | 4,527 | 4,075 | 3,579 | 2,559 | 2,942 | 3,622 |

## 70th Percentile Sales and Load Forecast

### Average Load (aMW) - 70th Percentile

| | Jan. 2027 | Feb. 2027 | Mar. 2027 | Apr. 2027 | May. 2027 | Jun. 2027 | Jul. 2027 | Aug. 2027 | Sep. 2027 | Oct. 2027 | Nov. 2027 | Dec. 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 1,021 | 885 | 765 | 580 | 573 | 742 | 920 | 920 | 702 | 688 | 854 | 1,078 |
| Commercial | 664 | 642 | 623 | 553 | 597 | 692 | 738 | 731 | 646 | 622 | 628 | 676 |
| Irrigation | 0 | 0 | 5 | 105 | 288 | 534 | 606 | 479 | 302 | 74 | 2 | 2 |
| Industrial | 388 | 375 | 377 | 367 | 376 | 401 | 391 | 401 | 394 | 401 | 395 | 394 |
| Additional Firm | 164 | 165 | 162 | 160 | 161 | 152 | 163 | 161 | 158 | 159 | 162 | 166 |
| Loss | 198 | 182 | 169 | 200 | 232 | 253 | 287 | 272 | 218 | 188 | 198 | 227 |
| Firm Load | 2,436 | 2,248 | 2,100 | 1,965 | 2,226 | 2,774 | 3,106 | 2,963 | 2,420 | 2,132 | 2,238 | 2,543 |
| Light Load | 2,252 | 2,096 | 1,943 | 1,771 | 1,998 | 2,508 | 2,783 | 2,653 | 2,160 | 1,909 | 2,080 | 2,361 |
| Heavy Load | 2,594 | 2,362 | 2,214 | 2,107 | 2,422 | 2,968 | 3,339 | 3,208 | 2,627 | 2,307 | 2,365 | 2,688 |
| System Load | 2,436 | 2,248 | 2,100 | 1,965 | 2,226 | 2,774 | 3,106 | 2,963 | 2,420 | 2,132 | 2,238 | 2,543 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,436 | 2,248 | 2,100 | 1,965 | 2,226 | 2,774 | 3,106 | 2,963 | 2,420 | 2,132 | 2,238 | 2,543 |

### Peak Load (MW) - 95th Percentile

| | Jan. 2027 | Feb. 2027 | Mar. 2027 | Apr. 2027 | May. 2027 | Jun. 2027 | Jul. 2027 | Aug. 2027 | Sep. 2027 | Oct. 2027 | Nov. 2027 | Dec. 2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -115 | -112 | -109 | -109 | -144 | -193 | -247 | -242 | -189 | -125 | -113 | -113 |
| Demand Response (MW) | 0 | 0 | 0 | 0 | 0 | -84 | -82 | -75 | 0 | 0 | 0 | 0 |
| Firm Peak Load | 3,117 | 2,831 | 2,903 | 2,263 | 3,779 | 4,409 | 4,615 | 4,155 | 3,632 | 2,595 | 2,981 | 3,688 |
| System Peak (1 Hour) | 3,117 | 2,831 | 2,903 | 2,263 | 3,779 | 4,409 | 4,615 | 4,155 | 3,632 | 2,595 | 2,981 | 3,688 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 3,117 | 2,831 | 2,903 | 2,263 | 3,779 | 4,409 | 4,615 | 4,155 | 3,632 | 2,595 | 2,981 | 3,688 |

## 70th Percentile Sales and Load Forecast Annual Summary

### Billed Sales (MWh) - 70th Percentile

| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 5,406,449 | 5,519,177 | 5,607,822 | 5,704,610 | 5,759,539 | 5,818,634 | 5,857,860 | 5,899,681 | 6,001,595 | 6,047,071 |
| Commercial | 4,031,788 | 4,114,624 | 4,205,782 | 4,291,241 | 4,356,369 | 4,424,778 | 4,474,860 | 4,525,631 | 4,616,109 | 4,662,988 |
| Irrigation | 1,754,686 | 1,751,251 | 1,749,602 | 1,745,944 | 1,742,301 | 1,739,424 | 1,730,949 | 1,733,909 | 1,736,819 | 1,731,189 |
| Industrial | 2,411,609 | 2,460,859 | 2,515,918 | 2,563,563 | 2,607,249 | 2,650,684 | 2,685,765 | 2,732,383 | 2,781,434 | 2,810,881 |
| Additional Firm | 1,168,602 | 1,472,472 | 1,509,783 | 1,512,208 | 1,468,718 | 1,466,455 | 1,462,890 | 1,463,064 | 1,466,036 | 1,459,239 |
| Firm Sales | 4,773,134 | 15,318,384 | 15,588,906 | 15,817,567 | 15,934,177 | 16,099,974 | 16,212,324 | 16,354,669 | 16,601,993 | 16,711,367 |
| System Sales | 4,773,134 | 15,318,384 | 15,588,906 | 15,817,567 | 15,934,177 | 16,099,974 | 16,212,324 | 16,354,669 | 16,601,993 | 16,711,367 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Sales | 4,773,134 | 15,318,384 | 15,588,906 | 15,817,567 | 15,934,177 | 16,099,974 | 16,212,324 | 16,354,669 | 16,601,993 | 16,711,367 |

### Generation Month Sales (MWh) - 70th Percentile

| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 5,432,748 | 5,525,803 | 5,614,938 | 5,708,787 | 5,782,778 | 5,821,569 | 5,860,805 | 5,906,581 | 6,024,035 | 6,050,076 |
| Commercial | 4,047,538 | 4,119,613 | 4,210,673 | 4,295,119 | 4,372,701 | 4,427,833 | 4,477,699 | 4,530,509 | 4,631,795 | 4,664,803 |
| Irrigation | 1,754,697 | 1,751,254 | 1,749,603 | 1,745,945 | 1,742,310 | 1,739,421 | 1,730,951 | 1,733,912 | 1,736,822 | 1,731,190 |
| Industrial | 2,414,715 | 2,465,851 | 2,520,663 | 2,567,677 | 2,610,442 | 2,655,148 | 2,688,627 | 2,736,533 | 2,785,052 | 2,814,178 |
| Additional Firm | 1,168,602 | 1,472,472 | 1,509,783 | 1,512,208 | 1,468,718 | 1,466,455 | 1,462,890 | 1,463,064 | 1,466,036 | 1,459,239 |
| Firm Sales | 4,818,299 | 15,334,994 | 15,605,660 | 15,829,736 | 15,976,950 | 16,110,426 | 16,220,972 | 16,370,598 | 16,643,741 | 16,719,486 |
| System Sales | 4,818,299 | 15,334,994 | 15,605,660 | 15,829,736 | 15,976,950 | 16,110,426 | 16,220,972 | 16,370,598 | 16,643,741 | 16,719,486 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Sales | 4,818,299 | 15,334,994 | 15,605,660 | 15,829,736 | 15,976,950 | 16,110,426 | 16,220,972 | 16,370,598 | 16,643,741 | 16,719,486 |
| Loss | 1,459,706 | 1,497,078 | 1,523,925 | 1,547,797 | 1,566,221 | 1,581,407 | 1,594,266 | 1,609,518 | 1,637,654 | 1,646,402 |
| Required Generation | 6,278,005 | 16,832,072 | 17,129,585 | 17,377,533 | 17,543,171 | 17,691,834 | 17,815,238 | 17,980,116 | 18,281,395 | 18,365,888 |

### Average Load (aMW) - 70th Percentile

| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 618 | 631 | 641 | 652 | 658 | 665 | 669 | 674 | 686 | 691 |
| Commercial | 461 | 470 | 481 | 490 | 498 | 505 | 511 | 517 | 527 | 533 |
| Irrigation | 200 | 200 | 200 | 199 | 198 | 199 | 198 | 198 | 198 | 198 |
| Industrial | 275 | 281 | 288 | 293 | 297 | 303 | 307 | 312 | 317 | 321 |
| Additional Firm | 133 | 168 | 172 | 173 | 167 | 167 | 167 | 167 | 167 | 167 |
| Loss | 166 | 171 | 174 | 177 | 178 | 181 | 182 | 184 | 186 | 188 |
| Firm Load | 1,853 | 1,921 | 1,955 | 1,984 | 1,997 | 2,020 | 2,034 | 2,053 | 2,081 | 2,097 |
| Light Load | 1,686 | 1,748 | 1,779 | 1,804 | 1,817 | 1,837 | 1,850 | 1,867 | 1,893 | 1,907 |
| Heavy Load | 1,984 | 2,058 | 2,093 | 2,124 | 2,139 | 2,163 | 2,178 | 2,198 | 2,228 | 2,246 |
| System Load | 1,853 | 1,921 | 1,955 | 1,984 | 1,997 | 2,020 | 2,034 | 2,053 | 2,081 | 2,097 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 1,853 | 1,921 | 1,955 | 1,984 | 1,997 | 2,020 | 2,034 | 2,053 | 2,081 | 2,097 |

### Peak Load (MW) - 95th Percentile

| | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -30 | -46 | -61 | -76 | -92 | -107 | -123 | -135 | -146 | -157 |
| Demand Response (MW) | -66 | -78 | -82 | -82 | -82 | -82 | -82 | -82 | -82 | -82 |
| Firm Peak Load | 3,284 | 3,383 | 3,446 | 3,511 | 3,558 | 3,617 | 3,666 | 3,723 | 3,793 | 3,846 |
| System Peak (1 Hour) | 3,284 | 3,383 | 3,446 | 3,511 | 3,558 | 3,617 | 3,666 | 3,723 | 3,793 | 3,846 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loss | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 3,284 | 3,383 | 3,446 | 3,511 | 3,558 | 3,617 | 3,666 | 3,723 | 3,793 | 3,846 |

## 70th Percentile Sales and Load Forecast Annual Summary

### Billed Sales (MWh) - 70th Percentile

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 6,092,896 | 6,185,469 | 6,293,332 | 6,404,538 | 6,517,008 | 6,629,038 | 6,741,617 | 6,855,549 | 6,978,555 | 7,098,019 |
| Commercial | 4,697,953 | 4,790,210 | 4,893,302 | 4,999,267 | 5,109,859 | 5,221,664 | 5,338,038 | 5,456,192 | 5,578,226 | 5,699,631 |
| Irrigation | 1,733,400 | 1,736,359 | 1,739,433 | 1,742,480 | 1,745,480 | 1,748,474 | 1,751,469 | 1,754,517 | 1,757,473 | 1,760,269 |
| Industrial | 2,857,163 | 2,905,486 | 2,962,268 | 3,012,134 | 3,064,480 | 3,117,298 | 3,172,855 | 3,227,871 | 3,309,541 | 3,394,606 |
| Additional Firm | 1,458,939 | 1,458,839 | 1,461,536 | 1,454,039 | 1,453,139 | 1,443,139 | 1,445,036 | 1,432,339 | 1,421,239 | 1,411,239 |
| Firm Sales | 6,840,351 | 17,076,364 | 17,349,871 | 17,612,458 | 17,889,966 | 18,159,612 | 18,449,015 | 18,726,468 | 19,045,034 | 19,363,764 |
| System Sales | 6,840,351 | 17,076,364 | 17,349,871 | 17,612,458 | 17,889,966 | 18,159,612 | 18,449,015 | 18,726,468 | 19,045,034 | 19,363,764 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Sales | 6,840,351 | 17,076,364 | 17,349,871 | 17,612,458 | 17,889,966 | 18,159,612 | 18,449,015 | 18,726,468 | 19,045,034 | 19,363,764 |

### Generation Month Sales (MWh) - 70th Percentile

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 6,099,009 | 6,192,568 | 6,320,697 | 6,411,872 | 6,524,277 | 6,636,308 | 6,770,076 | 6,862,937 | 6,985,669 | 7,104,797 |
| Commercial | 4,702,699 | 4,795,332 | 4,912,381 | 5,004,560 | 5,115,184 | 5,227,038 | 5,358,435 | 5,461,640 | 5,583,610 | 5,704,936 |
| Irrigation | 1,733,402 | 1,736,361 | 1,739,443 | 1,742,483 | 1,745,482 | 1,748,476 | 1,751,479 | 1,754,519 | 1,757,475 | 1,760,271 |
| Industrial | 2,861,277 | 2,909,639 | 2,966,392 | 3,017,181 | 3,069,076 | 3,122,075 | 3,176,821 | 3,233,353 | 3,316,711 | 3,401,936 |
| Additional Firm | 1,458,939 | 1,458,839 | 1,461,536 | 1,454,039 | 1,453,139 | 1,443,139 | 1,445,036 | 1,432,339 | 1,421,239 | 1,411,239 |
| Firm Sales | 6,855,326 | 17,092,739 | 17,400,449 | 17,630,134 | 17,907,158 | 18,177,036 | 18,501,847 | 18,744,787 | 19,064,704 | 19,383,178 |
| System Sales | 6,855,326 | 17,092,739 | 17,400,449 | 17,630,134 | 17,907,158 | 18,177,036 | 18,501,847 | 18,744,787 | 19,064,704 | 19,383,178 |
| Firm Off-System Sales | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Sales | 6,855,326 | 17,092,739 | 17,400,449 | 17,630,134 | 17,907,158 | 18,177,036 | 18,501,847 | 18,744,787 | 19,064,704 | 19,383,178 |
| Loss | 1,659,878 | 1,684,385 | 1,715,335 | 1,739,502 | 1,767,607 | 1,795,567 | 1,827,850 | 1,853,015 | 1,885,664 | 1,918,006 |
| Required Generation | 8,515,203 | 18,777,124 | 19,115,784 | 19,369,636 | 19,674,765 | 19,972,603 | 20,329,697 | 20,597,803 | 20,950,368 | 21,301,184 |

### Average Load (aMW) - 70th Percentile

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential | 696 | 707 | 720 | 732 | 745 | 758 | 771 | 783 | 797 | 811 |
| Commercial | 537 | 547 | 559 | 571 | 584 | 597 | 610 | 623 | 637 | 651 |
| Irrigation | 198 | 198 | 198 | 199 | 199 | 200 | 199 | 200 | 201 | 201 |
| Industrial | 327 | 332 | 338 | 344 | 350 | 356 | 362 | 369 | 379 | 388 |
| Additional Firm | 167 | 167 | 166 | 166 | 166 | 165 | 165 | 164 | 162 | 161 |
| Loss | 189 | 192 | 195 | 199 | 202 | 205 | 208 | 212 | 215 | 219 |
| Firm Load | 2,114 | 2,144 | 2,176 | 2,211 | 2,246 | 2,280 | 2,314 | 2,351 | 2,392 | 2,432 |
| Light Load | 1,922 | 1,949 | 1,979 | 2,011 | 2,043 | 2,074 | 2,105 | 2,138 | 2,175 | 2,211 |
| Heavy Load | 2,264 | 2,296 | 2,330 | 2,367 | 2,405 | 2,442 | 2,478 | 2,518 | 2,561 | 2,603 |
| System Load | 2,114 | 2,144 | 2,176 | 2,211 | 2,246 | 2,280 | 2,314 | 2,351 | 2,392 | 2,432 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Load | 2,114 | 2,144 | 2,176 | 2,211 | 2,246 | 2,280 | 2,314 | 2,351 | 2,392 | 2,432 |

### Peak Load (MW) - 95th Percentile

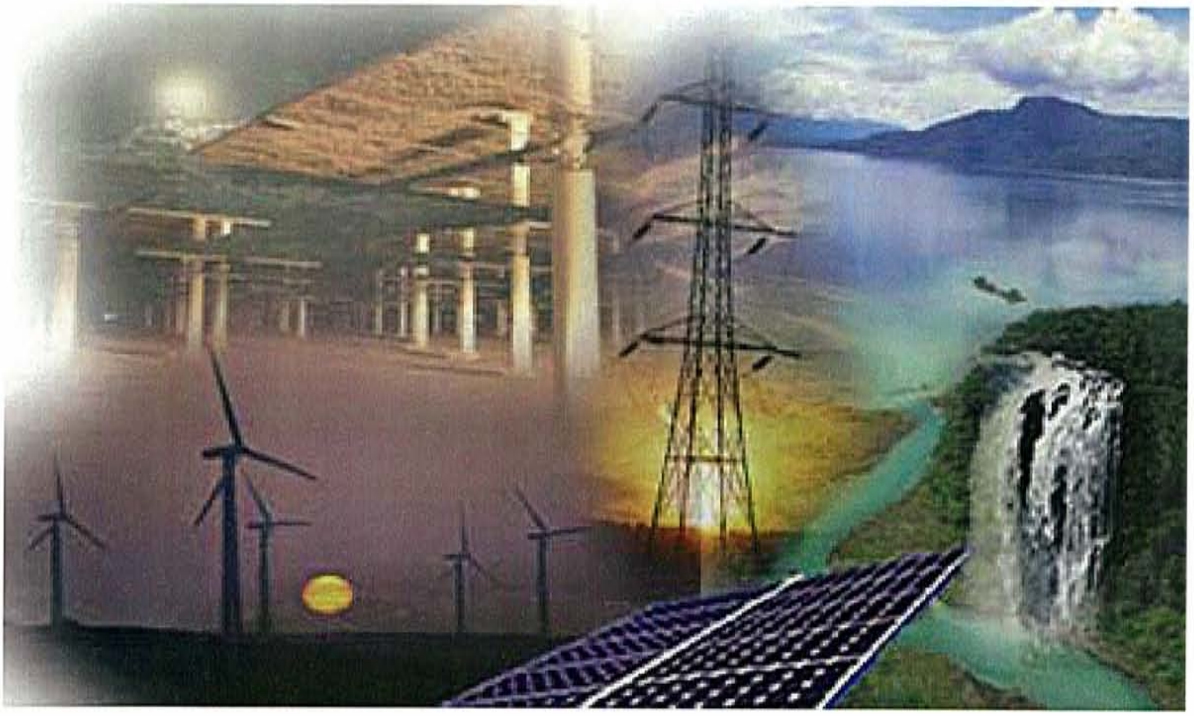
| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|---|---|
| Energy Efficiency (MW) | -168 | -179 | -190 | -200 | -210 | -219 | -229 | -239 | -243 | -247 |
| Demand Response (MW) | -82 | -82 | -82 | -82 | -82 | -82 | -82 | -82 | -82 | -82 |
| Firm Peak Load | 3,901 | 3,972 | 4,047 | 4,124 | 4,202 | 4,280 | 4,359 | 4,440 | 4,527 | 4,615 |
| System Peak (1 Hour) | 3,901 | 3,972 | 4,047 | 4,124 | 4,202 | 4,280 | 4,359 | 4,440 | 4,527 | 4,615 |
| Firm Off-System Peak | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loss | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Peak Load | 3,901 | 3,972 | 4,047 | 4,124 | 4,202 | 4,280 | 4,359 | 4,440 | 4,527 | 4,615 |

APPENDIX A-5-K

# Western Electricity Coordinating Council

# 2007 Power Supply Assessment

**FINAL DRAFT:**
**17 September 07**



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# EXECUTIVE SUMMARY

## Summary

The 2007 Western Electricity Coordinating Council (WECC) Power Supply Assessment (PSA) is an assessment of generation resource capacity margins (in MW) for the WECC summer and winter peak hours for the forecast period 2008 through 2016. This PSA also includes an energy assessment (GWh) for the Pacific Northwest prepared by Bonneville Power Administration (BPA) and the Northwest Power and Conservation Council.[1] The capacity assessment was conducted by the WECC staff during the second quarter of 2007, based on data that was requested in the fall of 2006 and submitted by WECC member utilities in the winter of 2006-07.

The capacity assessment identifies sub-regions within WECC that have the potential for electricity supply shortages based on reported demand, resource, and transmission data. The Supply Adequacy Model ("SAM") used to conduct the assessment includes 26 zones that are aggregated to make the seven sub-regions shown in the graphs. The capacity margin by sub-region, shown in the graphs, is a measure of a sub-region's ability to meet its load requirements, including a specified reserve amount, with resources in the sub-region and imports from other sub-regions, as calculated by SAM[2]. A capacity margin equal to or greater than zero denotes that the target, including the reserve margin, was met. A capacity margin of less than zero means that the sub-region's native generation and calculated imports were less than the target amount.

The graphs for both summer and winter capacity margins, Cases 1 and 2, respectively, portray a need for future resources beyond those already under active construction and after accounting for the potential for imports from the sub-regions with capacity surpluses. Resources have been proposed to meet a portion of these needs. A significant number of these are not under active construction although they are undergoing regulatory review. Others, as noted later in this Executive Summary and in Attachment 7 have not yet been proposed for regulatory review. It is also clear that the sub-region capacity margin varies significantly throughout the WECC region.

Note that the summer and the winter analyses for the Northwest sub-region do not adequately capture the limitations on the ability of the Northwest hydro system to sustain capacity output levels beyond a single hour. While sub-regional models run by Northwest parties indicate that the Northwest has surplus over its own needs, no firm decisions should be made about the magnitude of surplus capacity available to meet loads in other sub-regions based on this report. Loads and Resources Subcommittee (LRS) members report that these surpluses are not available for advance heavy load-hour contract commitments in summer months.

Results that indicate deficits below target reserve levels in later years of the assessment period are not forecasts of shortages. Rather, they are an indication that proposed resources need to be brought along through regulatory approval to construction at appropriate speed. At some point, the study results shift from an evaluation of supply margin to a determination of future needs and investment opportunities.

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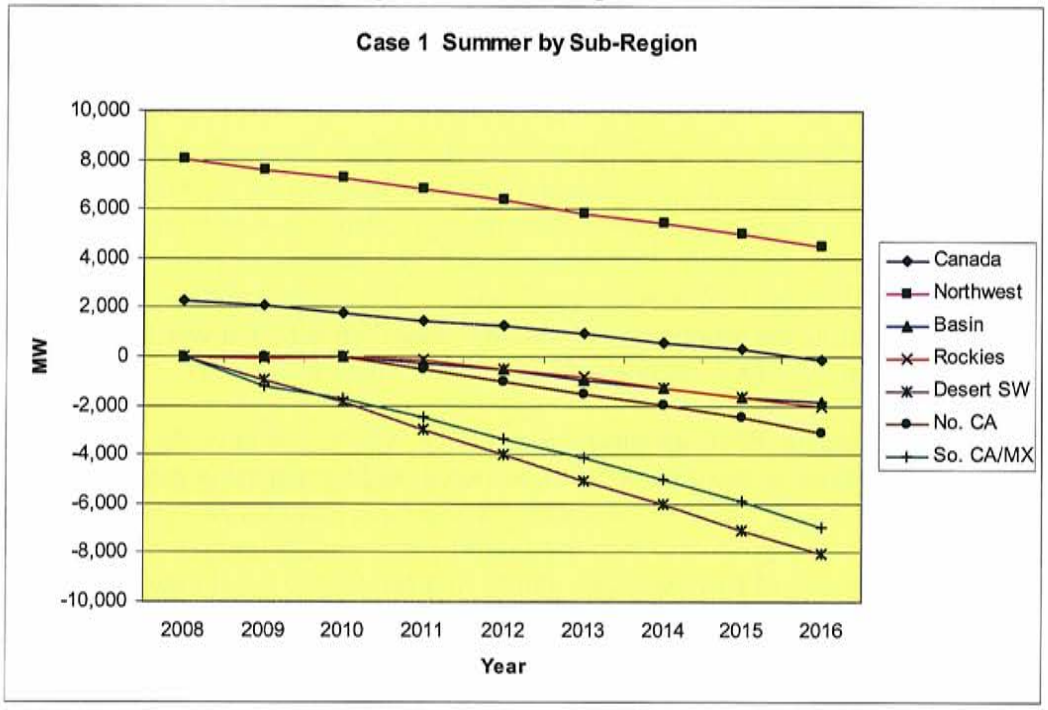
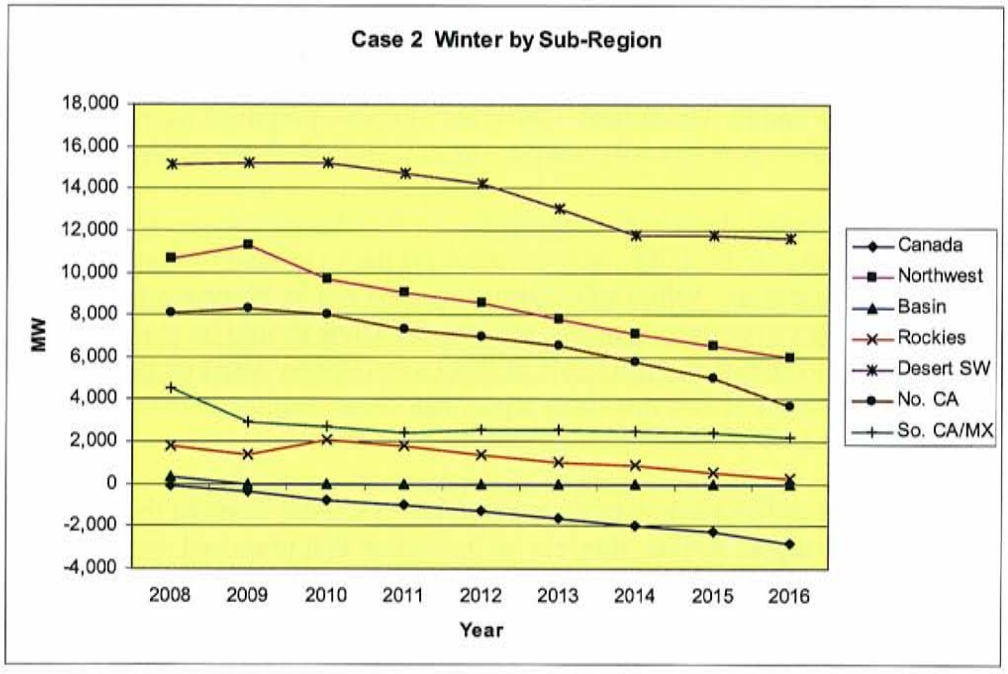
[1] See Attachment 6. This attachment was independently prepared and was not compiled by WECC staff or LRS.
[2] SAM, which was developed by the California Energy Commission (CEC), calculates transfers that are physically possible and economically justifiable, but they do not reflect any underlying contractual or other commitments.

**Graph 1 – Sub-Regional Resource Surplus/Deficit Summer Period**




**Graph 2 – Sub-Regional Resource Surplus/Deficit Winter Period**




As summarized in Tables 1 and 2, a total of eleven cases are included in the 2007 PSA. Each case evaluates whether there are sufficient resources (e.g., local generation including near-term additions and transmission import capacity) in each of the twenty-six defined zones to meet the

peak load forecast requirements plus a reserve margin. The cases are distinguished by season, by the amount of new generation that is included in addition to existing resources, by the location and intensity of the extreme weather impact and by the reserve margin that it tries to meet.

Table 1 provides a description of the cases that were developed using the different seasons, margin definitions and amounts of new resources. The definitions of the resource classes are on page 6.

**Table 1 – Case Description**

| Case | Season | New Resources | Margin |
|---|---|---|---|
| 1 | Summer | Class 1 | Building Blocks |
| 2 | Winter | Class 1 | Building Blocks |
| 3 | Summer | Classes 1 + 2 | Building Blocks |
| 4 | Winter | Classes 1 + 2 | Building Blocks |
| 5 | Summer | Class 1 | 15% |

Table 2 provides a description of the temperature sensitivities that were studied. These sensitivities were only studied for a single season, summer 2010 or winter 2010-11, as appropriate. Because they were intended to examine the effect of weather stresses beyond what were addressed in the planning margin, the test margin was modified to exclude the reserve for additional forced outages and the 1-in-10 weather reserve component. This leaves only the reserve components for contingencies and regulation that are actually required in operating reserves.

**Table 2 – Temperature Sensitivity Cases**

| Temperature Sensitivities: Modified Building Blocks - 2010 only | | | |
|---|---|---|---|
| **Case** | **Season** | **New Resources** | **Temperature Definition** |
| 6 | Summer | Class 1 | July 24, 2006 temperature, 2010 demand |
| 7 | Summer | Classes 1+2 | July 24, 2006 temperature, 2010 demand |
| 8 | Summer | Class 1 | Calif., Ariz., S. Nev.: 1-in-20<br>Rest of West: 1-in-10 |
| 9 | Summer | Classes 1+2 | Calif., Ariz., S. Nev.: 1-in-20<br>Rest of West: 1-in-10 |
| 10 | Winter | Class 1 | Canada, NW, Basin, N. Calif.: 1-in-20<br>Rest of West: 1-in-10 |
| 11 | Winter | Classes 1+2 | Canada, NW, Basin, N. Calif.: 1-in-20<br>Rest of West: 1-in-10 |

The case and sensitivity variables are described below.

- **Reserve Margin**: The 2007 PSA uses a building block approach to calculate the reserve margins, developed from an evaluation of a number of uncertainties facing load serving entities. The building block approach has four elements: contingency reserves, regulating reserves, reserves for additional forced outages, and reserves for 1-in-10 weather events[3]. The building block values were developed by balancing authority and then aggregated by sub-regions for the analysis. The sub-regions and the values that were used are shown in Table 4, below.

- **Temperature Sensitivity**: The temperature sensitivity cases looked at the impact on the entire Western Interconnection when 1-in-20 year temperature occurred in different regions of the Interconnection. In addition, a case to look at the impact of a recurrence of an extreme temperature event such as the one on July 24th 2006 was created.

- **New Generation**: The following categories were defined for new resources additions (reported as of December 2006). Class 1 additions were used in all of the cases. Five of the cases also included Class 2 additions. Class 3 additions were listed for purposes of categorizing all reported projects but they were not included in any of the analyses. All new generation resources reported, including those in Class 3, are displayed in Attachment 7.

    - Class 1: Generation additions/retirements that were reported to be under active construction as of the reporting date of December 2006 and are projected to be in-service before January 2011.

    - Class 2: Generation additions/retirements that were reported to be under active regulatory review, with an expected in-service date before January 2013. This class includes resources that were expected to be in service as early as Class 1 resources but did not meet the test of being under construction, and resources that may not be completed/retired before the January 2011 date.

    - Class 3: Generation additions that were reported but did not meet the criteria for Class 1 or Class 2. Class 3 resources were not included in the analysis for the PSA. The exclusion of Class 3 resources was intended to highlight the importance of ongoing resource development and acquisition to bring resources on line at appropriate times.

Table 3 is a synopsis of the results showing the first year of deficiency for each sub-region by case. A deficit condition is an indication that a sub-region was unable to meet its load requirements plus the applicable reserve margin given the parameters for that case and assuming the non-contracted transfers quantified by the model actually occur. The deficit amount is the net shortage that the model is showing for the sub-region. The "year of first deficit" could also be considered as the year that additional facilities (besides those already included in the analysis) must be in-service to avoid deficiencies against the planning margin and highlights the need and opportunity for consistent investment in new resources (transmission and generation).

[3] See "Building Block Planning Reserve Margin" on page 13 for definitions and details.

**Table 3 - Year of First Deficit and Deficit Amount (MW)**

| Sub-Region | Scenario 1 Summer Base | Scenario 2 Winter Base | Scenario 3 Summer Base + | Scenario 4 Winter Base + | Scenario 5 Summer 15% |
|---|---|---|---|---|---|
| Canada | 2016 -158 | 2008 -56 | | 2009 -296 | 2015 -284 |
| Northwest | | | | | |
| Basin | 2011 -231 | | 2012 -289 | | 2010 -73 |
| Rockies | 2009 -44 | | 2011 -5 | | 2009 -313 |
| Desert Southwest | 2009 -944 | | 2011 -1,225 | | 2009 -626 |
| No. California | 2009 -26 | | 2013 -413 | | 2011 -111 |
| So. California/Mexico | 2009 -1,206 | | 2011 -270 | | 2009 -438 |

Blank indicates that no deficit occurred; Base + indicates Class 2 additions/retirements.

The results for the eleven cases are aggregated to seven sub-regions to mitigate modeling limitations and to maintain load forecast confidentiality in years two and three of the forecast period as required by Appendix B of the WECC Information Disclosure Policy. The deficit amount is the sum of the deficits in all of the zones in the sub-region. A deficit does not necessarily indicate that all of the zones in the sub-region are deficit. A surplus does not mean that all zones are surplus, as a surplus zone may mask a deficit in an adjacent zone, such as occurs within the Canada sub region. Table 4 below shows the SAM zones for each sub-region.[4]

Table 4 also shows the building block reserve margin values that were used for the sub-regions in the analysis. It is important to note that the values for reserve margins used in the PSA are NOT directly comparable to any values that might be used by individual load serving entities (LSEs) or their regulators or local governing boards to evaluate their individual resource adequacy. Moreover, they are not intended to supplant any of those values. Attachment 5 has more detail on this issue.

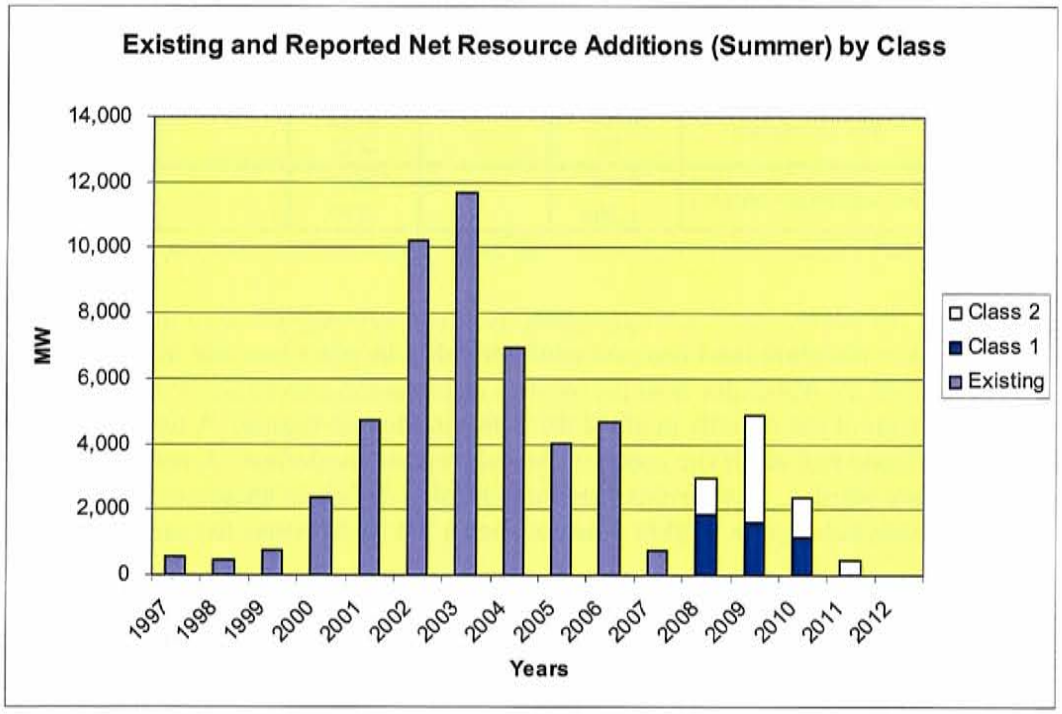
**Table 4 – SAM Zones and Building Block Margins**

| Sub-Region | SAM Zones Included in Sub-Area | Summer Margin | Winter Margin |
|---|---|---|---|
| Canada | British Columbia, Alberta | 12.0% | 12.8% |
| Northwest | Pacific Northwest, COB, Montana | 13.7% | 16.3% |
| Basin | Idaho, Northern Nevada, Utah, IPP | 12.8% | 13.5% |
| Rockies | Colorado East, Colorado West, Wyoming | 14.2% | 15.4% |
| Desert Southwest | Arizona, New Mexico, Southern Nevada, IID, Four Corners, Palo Verde | 15.7% | 14.6% |
| Northern California | Northern California, Central California San Francisco, SMUD | 16.5% | 12.5% |
| Southern California/Mexico | Southern California, San Diego, LADWP, Comision Federal de Electricidad (CFE) | 16.6% | 13.0% |
| WECC Total | | 15.0% | 14.1% |

[4] More detail on the SAM zones or "bubbles" is giving in Attachment 1.

Graph 3 shows projected net resource additions in summer from 2008 through 2012, using the resource definitions described earlier. Class 1 additions are planned projects that are under active construction and projected to be completed by January 2011. Class 2 additions are under active regulatory review, with in-service dates by January 2013. Class 3 additions, which are not shown in the graph and were not used in the 2007 PSA analysis, consist of all other reported new projects. More information about Class 3 resources is shown on page 15 and in Attachment 7.

**Graph 3 - Existing and Reported Net Resource Additions**




The 2007 PSA cases include load forecasts for the full term of the PSA studies (2008 – 2016). Forecasts for continued increases in new generation resources and/or transmission capacity, reported in the winter of 2006-07, based on late 2006 data, indicate future new generation projects ranging from new projects that are being contemplated to new projects that are nearing completion.

For this analysis, wind turbine capacity was derated, on average, based on utility submissions, to approximately 8% of nameplate capacity. The derated capacities are what is shown in Graph 3. Attachment 7, in listing the generation additions and retirements, shows the wind derates in aggregate as an individual line item.. The analysis of the appropriate capacity value for wind projects, particularly in geographically diverse developments, is still ongoing in a number of forums in the West.[5] The results will be used to inform future adequacy evaluations.[6]

[5] A CAISO study of the extreme conditions of July 2006 found that during the five-day period of July 21 – 26, 2006, that wind capacity during the peak hour averaged 12% of nameplate capacity on an integrated energy basis. During

The 2007 PSA also includes an energy assessment prepared by entities in the Pacific Northwest (PNW), which is a part of the Northwest sub-region. BPA and the NWPCC plan to continue their work with energy assessments in the future. Attachment 6 describes the PNW energy assessment and shows the large effect on energy supplies in the PNW depending on water conditions.

## Caveats--Observations--Recommendations

Among the important caveats (Items1-5) observations (Items 6-9) and recommendations (Items 10 and 11) that should be considered on reviewing these results are the following:

1. The analysis is based on loads and resources (L&R) data submitted in December 2006 and February 2007. This vintage will not include important changes that may have occurred. For example, the Palo Verde - Devers 2 line capability is included in the transmission between the Southern California and Desert Southwest sub-regions.

2. The assessment is based on the physical ability of the Interconnection to supply all loads regardless of contractual obligations. This means that the model uses economic relationships to calculate transfers between zones (within the assigned limits), and results in use of non-contracted resources being assumed to meet firm demand on peak in importing sub-regions. In reality, the assessment results may be difficult to duplicate in the actual operational environment. System operation for contract obligations and other conditions could adversely affect the availability of resources, and could impact the amount and timing of supply deficiencies in specific zones.

3. The Loads and Resources Subcommittee recognizes that the results of this assessment may differ from the results of similar assessments by other parties.

4. Despite attempts to achieve uniform reporting through the L&R reporting instructions, there are known variations among the critical areas that can create ambiguities. The methods used to de-rate hydro generation from its nameplate to adverse capacity are a good example.

5. Unlike prior years, the PSA does not include evaluation for the current year, but begins the study in 2008. This change was made due to the time required to complete the study. (By the time the report is issued the 2007 year will have largely passed.)

6. A determination that a zone has sufficient resources and imports to meet its load requirement does not necessarily mean that all of the demand centers within that zone can meet their load requirements. Transmission constraints internal to a zone may limit capacity transfers to local demand areas, leaving them without a positive margin. These transmission-constrained local demand areas may include one or more major metropolitan areas within a zone and may include most of the total population within a zone.

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specific days of this period, wind performance during the peak hour ranged from 6 to 23% of nameplate capacity on an integrated energy basis. CAISO, March 2007.

[6] A sensitivity analysis using 0% capacity value was done, but given the low base capacity value (8%) and the limited wind penetration in Classes 1 and 2, the effect was minor. In future years, the sensitivity to this value will be substantially more, with expected wind penetrations under renewable portfolio standards, and the importance of the ongoing analysis of this variable will be correspondingly high.

7. It is logical to expect that more generation projects will be built as they are needed and as older projects are retired. At some point, the study results shift from a determination of supply margin to an estimate of future resource needs.

8. Using non-coincidental demands overstates the simultaneous demand. Preliminary studies indicate that the simultaneous combined peak demand for WECC is lower by 1% to 3%, compared to the non-simultaneous demand.

9. Surplus generation in the Pacific Northwest was stranded, but neither the summer nor the winter analysis for the Northwest sub-region captures the limitations on the ability of the hydro system to sustain output levels beyond a single hour. The reported Northwest surpluses for potential export to other sub-regions of the West are unrealistically high.

10. The effects of fuel diversity and availability should be modeled in future assessments. Improved analyses should evaluate the impact of fuel shortages due to fuel supply interruptions or demand spikes.

10. Expanding the energy assessment to other sub-regions and zones, where relevant, is a goal for the future. It is expected that the data and manpower requirements for energy assessments could be higher than for this peak hour capacity assessment. A more sophisticated model would also be needed. The LRS work plan includes steps to take action on this.

Final Draft 17 Sep07

# 2007 Power Supply Assessment

## Purpose and Background

The WECC PSA evaluates the resource capacity margins of sub-regions of the western interconnection. It identifies sub-regions within WECC that have the potential for electricity supply shortages based on reported demand and resource data, assumed non-contracted economic transfers and considering transmission constraints between the sub-regions.

The WECC Loads and Resources Subcommittee (LRS) has the responsibility to establish the tools, methodology, and data requirements for conducting the power supply assessment annually. The responsibility is described in the attached document entitled "WECC Power Supply Assessment Policy" (Attachment 3).

The purpose of this report is to present the results of the power supply assessment that was conducted during the second quarter of 2007. The studies cover the summer period from 2008 through 2016, and the winter period from 2008/09 through 2016/17. The input data represent the control area Loads and Resources (L&R) data submitted in December 2006. The "SAM" model that was developed by the California Energy Commission was used to produce the results for the assessment.

The Pacific Northwest energy assessment (Attachment 6) evaluated the energy limitations of the predominantly hydro system in this specific zone within the Northwest sub-region.

### Key Definitions

**Class 1 Generation Additions** – planned generation additions (projects) that are currently under active construction and projected to be in-service by January 2011.

**Class 1 Generation Retirements** – planned generation retirements or planned long term shutdowns that will take place by January 2011.

**Class 2 Generation Additions** – planned generation additions (projects) that are currently under active regulatory review with a projected in-service date prior to January 2013.

**Class 2 Generation Retirements** – planned generation retirements or planned long term shutdowns that will take place prior to January 2013.

**Class 3 Resources** – planned resource changes (additions, retirements, etc.) that do not meet the criteria for Class 1 or Class 2. Class 3 changes were not included in any of the cases of this assessment.

**Existing Generation** – generation that was available (in-service) as of December 31, 2006.

**Peak Demand** – demand or load that is expected to be served during the peak hour of the month being studied. The peak demand in this assessment is the total demand (firm demand plus non-firm demand as reported by the control areas). Note that in this assessment, demand is synonymous with load.

**Power Supply Margin** – PSA result identifying the amount of available resource capacity (including net imports as calculated in SAM) in excess of the demand requirements, after applying the specified adjustments to both demand and resources and accounting for the non-contracted zonal transfers calculated by the model (see discussion below).

**Restricted Transfer Capabilities** – These are the transfer capabilities that may reasonably be expected to apply under simultaneous high seasonal adverse transmission loading conditions.

**Power Supply Margin versus Reserve Margin**

It is important to understand the relationship between the output of the SAM model and a reserve margin calculation. In equation form the SAM output, referred to as power supply margin, is

**Power Supply Margin = Resource Capacity + Imports – Exports – Load Requirement**

(where both Resource Capacity and Load Requirement include case adjustments)

While this equation is very similar to the equation for calculating a reserve margin, the key difference is that the SAM model also calculates the Imports and Exports during its solution. When the internal resource capacity for a zone is less than the load requirement, SAM will import additional capacity, if available, to meet the load requirement. For example, if the resource capacity for a zone is 1,000 MW and the load requirement is 2,000 MW, SAM will attempt to import 1,000 MW to make up the difference. Assuming that there are no exports, the power supply margin is then (1,000 + 1,000 – 0 – 2,000) = 0 MW and the load requirement is met.

In order to model a reserve margin with SAM, it is necessary to apply the desired or assumed reserve margin as an input parameter prior to running SAM. This is done by increasing the load and/or decreasing the resource capacity by the reserve margin factor. Then as long as the power supply margin is not negative, the reserve margin has been met.

## Synopsis of Input Data

The input data consists of the following data collected from the WECC control areas.

a) Generation capacities including planned additions and retirements.
b) Monthly peak demand forecasts.
c) Generation outage forecasts.
d) Zone to zone transfer capabilities.
e) Load temperature sensitivity data in megawatts per degree Fahrenheit.

The generation capabilities represent the expected seasonal available capacities. The peak demands represent the 1-in-2 probability load forecasts, and include the expected firm and non-firm demand for the peak hour of the study month. It was assumed that the forecast monthly non-coincidental peak demands for each zone will occur at the same time (no diversity). Studies indicate that the simultaneous combined peak demand for WECC is approximately 1% to 3% less than the non-simultaneous demand.

## Building Block Planning Reserve Margin

The reserve margins for all of the cases except Case 5 were based on the building block guideline developed by the LRS, approved by the Planning Coordination Committee (PCC) and approved by the Board at the July, 2007 Board of Directors' meeting. The building block guideline/targets are made up of four elements:

1. Contingency Reserves - An additional amount of operating reserve sufficient to reduce area control error (ACE) to zero in 10 minutes following loss of generating capacity, which would result from the most severe single contingency. The contingency calculation was done using resource data collected through the 2006 L&R data request. The minimum operating reserve criteria (MORC) require that hydro resources have five percent reserves, and that non-hydro resources have seven percent reserves. The reserve requirement for each Balancing Authority (BA) was calculated using a weighed average of hydro and non-hydro requirements. Therefore, for BAs with no hydro resources the contingency requirement is seven percent and for BAs with only hydro resources, the contingency is five percent. NERC and WECC standards require that contingency reserves be carried by BAs (individually or through reserve sharing pools).

2. Regulating Reserves - The amount of spinning reserves responsive to automatic generation control (AGC) that is sufficient to provide normal regulating margin. The regulating component of the guideline was calculated using responses received in the 2007 PSA data request. BAs were asked how much regulating reserve they would expect to carry during 2007, as either a MW number or as a percentage of load. MW responses were converted to a percentage of load by dividing the MW provided by the forecasted 2006 peak demand. A "sanity" check was done to all responses and those that seemed unreasonably low or high and were replaced by the weighted average of reported regulating reserves. NERC and WECC standards require regulating reserves to be carried by BAs.

3. Additional Forced Outages - An unplanned component failure (immediate, delayed, or postponed) or other condition that requires that the unit either immediately or before the next weekend, be reduced or removed from service. Reserves for additional forced outages, beyond what might be covered by operating reserves in order to cover second contingencies, were calculated using the forced outage data supplied to WECC through the L & R data request. Five years of data (2001-2005) were averaged to calculate both a summer (July) and winter (December) forced outage rate. The actual calculation is total forced outages (data code 16) divided by total resources reported in the L&R request (data codes 3 through 13). The same forced outage rate was used for all BAs in WECC when calculating the building block guideline. These reserves are not required to be carried by BAs by NERC or WECC standards.

4. Temperature Adders - Using historic temperature data for up to 15 years, the annual maximum and minimum temperature for each BA's area[7] was identified. That data was used to calculate the average maximum (summer) and minimum (winter) temperature and the associated standard deviation. The standard deviation was multiplied by a 90% probability factor and added to the average historic temperature to convert from a 1-in-2

[7] For the CAISO, which covers three SAM zones with significantly varying weather and load responses, the analysis was done by zone, rather than for the ISO as a whole.

temperature (50 percent exceedence) condition to a 1-in-10 (10 percent exceedence) condition. The 1-in-2 temperature was subtracted from the 1-in-10 temperature to calculate the temperature change associated with the 1-in-10 outlook. The temperature change was then multiplied by the MW per degree change supplied by the individual BAs to arrive at a MW increase associated with converting from a 1-in-2 temperature related forecast to a 1-in-10 forecast. This MW change was divided by the forecast peak demand from 2006 to create a percentage change to be applied to future demand forecasts to convert from a 1-in-2 forecast to a 1-in-10 forecast. These reserves are not required to be carried by BAs by NERC or WECC standards.

Tables 5 and 6 show the reserves, in MW and percent of load by sub-region that were calculated using the building blocks. Note that this calculation produces a constant percentage margin above load over time.

**Table 5 - Summer Building Block Reserve Requirements by Sub-Region in MW and Seasonal Percent of Load**

| Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Average |
|---|---|---|---|---|---|---|---|---|---|---|
| Canada | 2,103 | 2,149 | 2,193 | 2,234 | 2,271 | 2,318 | 2,359 | 2,393 | 2,445 | 12.0% |
| Northwest | 3,286 | 3,321 | 3,366 | 3,407 | 3,444 | 3,488 | 3,533 | 3,580 | 3,638 | 13.7% |
| Basin | 1,800 | 1,851 | 1,899 | 1,940 | 1,983 | 2,026 | 2,075 | 2,128 | 2,178 | 14.2% |
| Rockies | 1,518 | 1,575 | 1,608 | 1,647 | 1,682 | 1,725 | 1,764 | 1,808 | 1,841 | 12.8% |
| Desert SW | 4,808 | 4,960 | 5,116 | 5,263 | 5,399 | 5,545 | 5,687 | 5,834 | 5,972 | 15.7% |
| No. CA | 4,525 | 4,599 | 4,678 | 4,756 | 4,835 | 4,915 | 4,992 | 5,073 | 5,157 | 16.5% |
| So. CA/MX | 5,867 | 5,944 | 6,045 | 6,146 | 6,265 | 6,354 | 6,464 | 6,574 | 6,704 | 16.6% |
| Total WECC | 23,908 | 24,401 | 24,904 | 25,393 | 25,879 | 26,372 | 26,874 | 27,390 | 27,935 | 15.0% |

**Table 6 - Winter Building Block Reserve Requirements by Sub-Region in MW and Seasonal Percent of Load**

| Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Average |
|---|---|---|---|---|---|---|---|---|---|---|
| Canada | 2,796 | 2,851 | 2,912 | 2,952 | 2,997 | 3,057 | 3,104 | 3,153 | 3,214 | 12.8% |
| Northwest | 4,780 | 4,854 | 4,903 | 4,949 | 5,014 | 5,074 | 5,138 | 5,197 | 5,254 | 16.3% |
| Basin | 1,652 | 1,698 | 1,745 | 1,783 | 1,822 | 1,862 | 1,905 | 1,949 | 1,990 | 15.4% |
| Rockies | 1,291 | 1,356 | 1,389 | 1,409 | 1,446 | 1,478 | 1,510 | 1,540 | 1,558 | 13.5% |
| Desert SW | 2,795 | 2,882 | 2,975 | 3,052 | 3,130 | 3,212 | 3,291 | 3,378 | 3,461 | 14.6% |
| No. CA | 2,344 | 2,367 | 2,391 | 2,415 | 2,440 | 2,464 | 2,488 | 2,512 | 2,536 | 12.5% |
| So. CA/MX | 3,281 | 3,321 | 3,359 | 3,397 | 3,429 | 3,475 | 3,517 | 3,559 | 3,594 | 13.0% |
| Total WECC | 18,939 | 19,330 | 19,674 | 19,958 | 20,278 | 20,623 | 20,953 | 21,287 | 21,607 | 14.1% |

It is important to note that the values for reserve margins used in the PSA are NOT directly comparable to any values that might be used by individual LSEs or their regulators or local governing boards to evaluate their individual resource adequacy. Moreover, they are not intended to supplant any of those values. A more complete description of this issue is given in Attachment 5.

## WECC Resource Additions

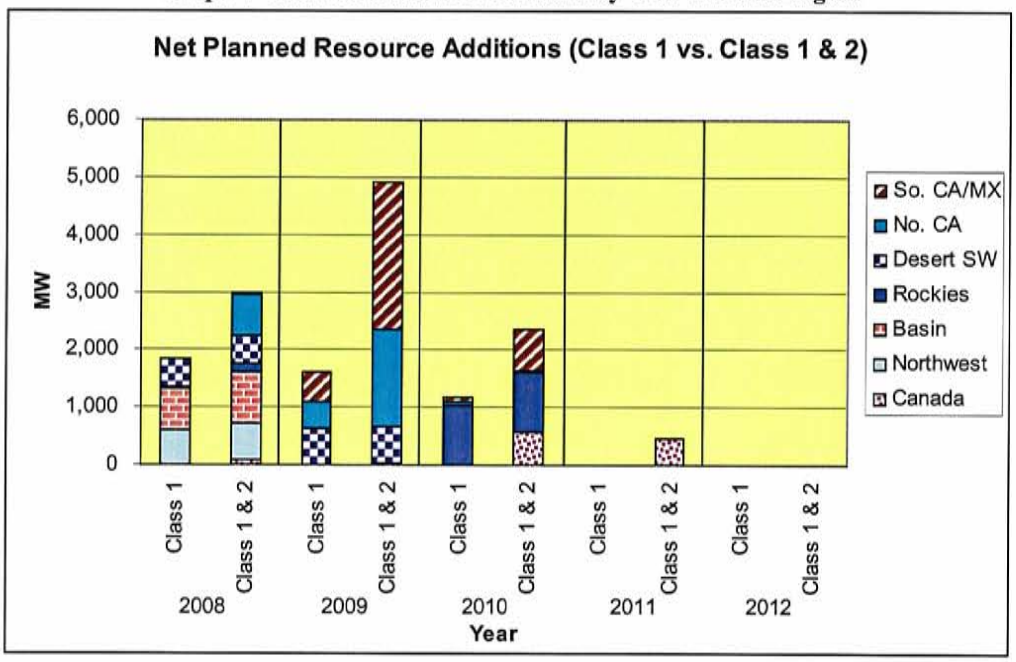
The Load and Resources data submittals included a list of planned generation additions, changes, and retirements. Table 7 is a summary of the WECC-reported resource additions by Class (summer and winter derated capacities). The majority of the reported projects are Class 3 additions (not under active construction nor proposed for regulatory review) and these projects were excluded from any of the analyses in this assessment. A detailed list of the identified generation projects is provided in Attachment 7.

**Table 7 – Planned Resource Additions by Class (Summer Derated Capacities)**

| WECC | Class | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 1,841 | 1,596 | 1,177 | 0 | 0 | 0 | 0 | 0 | 0 | 4,614 |
| | 2 | 1,131 | 3,310 | 1,170 | 462 | 12 | 0 | 0 | 0 | 0 | 6,085 |
| | 1 & 2 | 2,972 | 4,906 | 2,347 | 462 | 12 | 0 | 0 | 0 | 0 | 10,699 |
| | 3 | 8,338 | 8,361 | 5,068 | 3,903 | 2,679 | 2,962 | 937 | 1,499 | 214 | 33,961 |
| | Total | 11,310 | 13,267 | 7,415 | 4,365 | 2,691 | 2,962 | 937 | 1,499 | 214 | 44,660 |

Graph 4 compares Class 1 planned resource additions with both Class 1 and 2 planned additions by sub-region. By the definitions of Class 1 and Class 2 resources, no additions beyond 2012 are included in this graph. It is logical to expect that more projects will be built as they are needed and as older projects are retired. One of the purposes of this Power Supply Assessment is to apply reasonably uniform criteria in making resource assessments across WECC and its various sub-regions so that the industry can have confidence about the general need for additional resources and regulators can have a better understanding of the regional context within which they may make utility and state-specific determinations.

**Graph 4 –Planned Resource Additions by Year and Sub-region**



Nevertheless, caution needs to be exercised about the resources reported in Class 3. For example, as can be seen from the table above, there is a large amount of resource reported coming into service in the next few years. A large portion of this was reported by the California ISO which, because of California's market structure, has particular difficulty in verifying the status of future generation proposals.

The new generation additions reported by the CAISO were based on projects in the CAISO large generator interconnection queue, which included all projects requesting interconnection to the CAISO grid. A significant percentage of the projects in this queue are somewhat speculative and are either delayed or never built since they fail to obtain a contract for the output of the project, financing, or some other necessity for completing the project.

## Summary of Assessment Results by Case

The results that are reported in this report are a measure of the ability of the defined sub-regions to meet their load requirements with internal generation and imports from other sub-regions or zones under the specified conditions, as calculated by SAM. The Loads and Resources Subcommittee approved a set of study cases to model the criteria, but recognized that the interpretation and methodology are limited by the modeling tool.

### Case Descriptions

The common criteria used in all of the cases included: Existing Generation as of December 31, 2006, Class 1 Generation Additions, Scheduled Maintenance/Inoperable, Adverse Hydro, and Total Demand (firm plus nonfirm). The criteria that varied in the study cases are summarized in Table 8. Note that "Additions" refers to generation additions and retirements.

**Table 8 - Case Criteria Matrix**

| Criteria | #1 | #2 | #3 | #4 | #5 |
|---|---|---|---|---|---|
| Generation | | | | | |
| Class 2 Additions (under active regulatory review with a completion date prior to January 2013) | no | no | yes | yes | no |
| Peak Demands | | | | | |
| Peak Month | Jul | Dec | Jul | Dec | Jul |
| Reserve Requirement | Building Block | Building Block | Building Block | Building Block | 15% |
| Temperature Event | no | no | no | no | no |

### Result Aggregation

The assessment results are aggregated into seven defined sub-regions (see Table 9) due to limitations of the modeling and to main confidentiality of years 2 and 3 of the load forecast data. The actual zonal topology is presented in the bubble diagrams on pages 48 (summer) and 49 (winter). The colors of the zones (described as "bubbles") in the diagrams also identify the grouping of the zones into the aggregate sub-regions.

**Table 9 - Sub-Region Definitions**

| Sub-Region | Zones in Sub-Region |
|---|---|
| Canada | Alberta, British Columbia |
| Northwest | COB, Montana, Pacific Northwest |
| Basin | Idaho, No. Nevada, Utah, IPP |
| Rockies | Colorado-East, Colorado-West, Wyoming |
| Desert SW | Arizona, IID, Four Corners, New Mexico, Palo Verde, So. Nevada |
| No. CA | Central CA, Northern CA, San Francisco, SMUD |
| So. CA/MX | CFE-Mexico, Southern CA, San Diego, LADWP |

**Interpretation of Power Supply Margin Tabulations**

The Power Supply Margin Tables display the excess capacity in each sub-region for each year of the study. The sub-region values are the sum of the power supply margins for the zones in each sub-region. **If the power supply margin is zero or positive, then the combination of sub-region resources and sub-region imports calculated by the model is sufficient to meet or exceed the load requirements, including any reserve defined for the given case.**

A positive power supply margin implies that a sub-region has excess generation capacity that is either not needed by other sub-regions, or that there are transmission constraints that prevent the excess capacity from being delivered to other sub-regions that are deficit.

A zero margin is an indication that a sub-region is in load-resource balance or that there are transfers involved. The model will not import more capacity than is needed to cover the load requirement, but the load requirement has been met.

A negative power supply margin indicates that the combination of sub-region resources and sub-region imports were not sufficient to meet the load requirements. As long as WECC overall is not deficit, this means that there are one or more transmission constraints between the surplus sub-region(s) and the deficit sub-region(s). When the total WECC margin becomes negative, additional transmission capacity would not be able to resolve all sub-regional deficits.

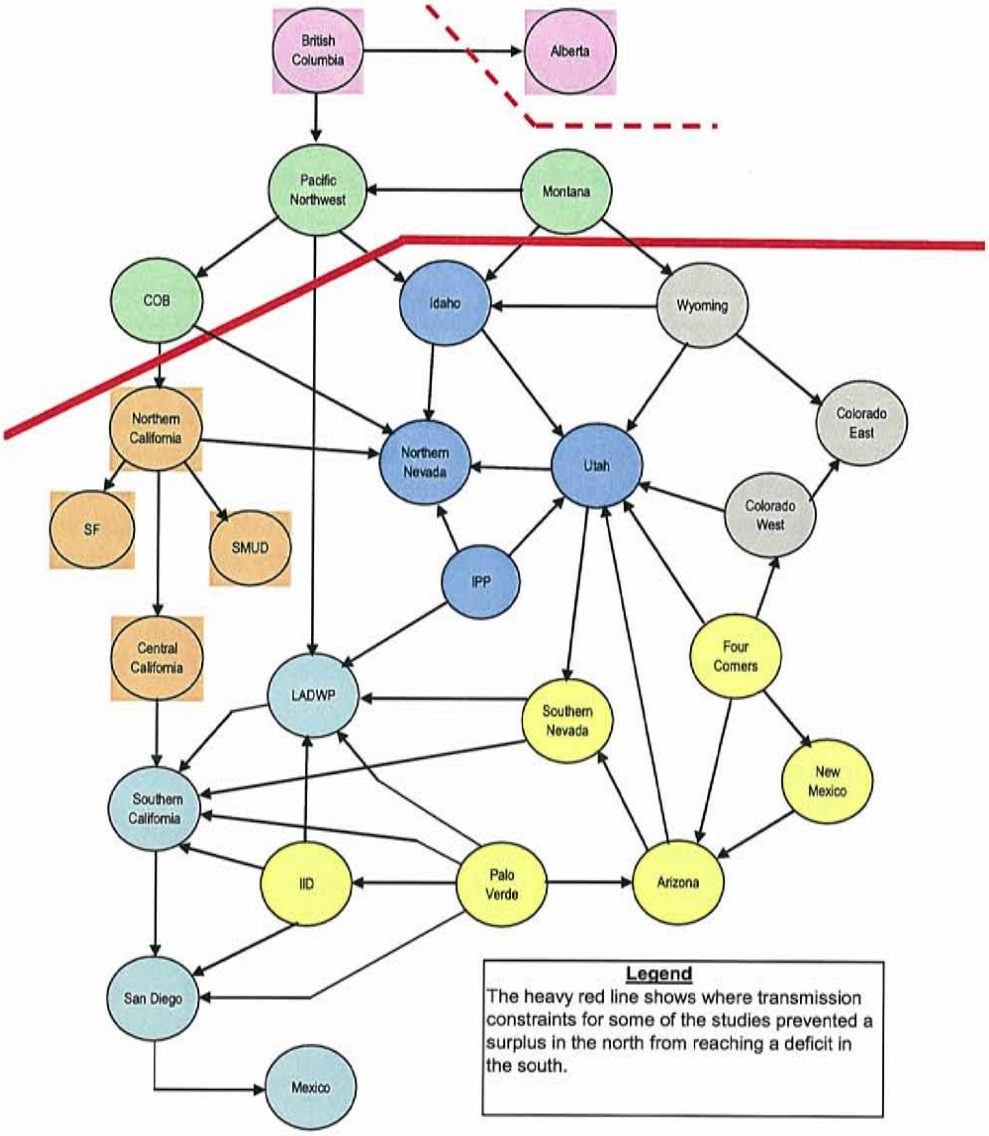
A non-negative power supply margin for a sub-region doesn't necessarily mean that the load requirements in all of the sub-region's zones were satisfied. The sub-region power supply margins are the sum of the zonal power supply margins, some of which could be negative.

**Result Summaries**

Summaries of the results for each case are presented in this section of the report. Additional details are presented in Attachment 2.

A condition called the "North-South split" shows up in this year's and previous PSA analyses. This occurs when the transmission system between the Northwest/British Columbia/Montana (the North)[8] and the areas to the south (the South) is insufficient to allow all reported surpluses north of the constraint to meet loads south of the constraint in the economic dispatch performed in SAM. The following diagram shows the location of this split as it appears in this year's analysis.

[8] Alberta does not contribute to the surplus.




Note that transmission may be constraining on exports from the North to the South in the summer cases following only because the reported surplus in the Northwest is so large. The real size of this surplus is likely to be substantially smaller due to the data issues mentioned earlier in this report, and may even be smaller than the otherwise constraining transmission paths. It is unlikely that additional summer capacity transfers out of the Northwest, other than what is already calculated in SAM, would be available under poor water conditions. This caveat needs to be taken into account in all the following summer cases.

In each of the following cases, two matrices are presented that summarize the capacity situation of each sub-region. The first matrix displays the power supply margin, in megawatts (MW). The yellow highlighting helps to show the deficits identified in the margin table. The second matrix displays the margin status of the individual zones within the sub-region. This matrix highlights the fact that individual zones within a sub-region may be deficit before the entire sub-region becomes deficit. The first of the annual columns shows the number of surplus zones, the second column shows the number of balanced zones, and the third column shows the number of zones within each sub-region that are deficit.

**Case #1 – Summer Modeling Building Block Reserve Guideline**

| Resource Parameters | |
|---|---|
| Existing Generation | Included |
| Class 1 Additions | Included |
| Class 2 Additions | Excluded |
| **Outages and De-rates** | |
| Adverse Hydro | Yes |
| Scheduled Maintenance | Yes |

| Demand/Load Parameters | |
|---|---|
| Firm Demand | Included |
| Non-firm Demand | Included |
| Reserve Margin | Building Block |
| Study Month | July |
| Temperature Event | No |
| Transfer Capability | Restricted |

This case models the building block reserve guideline formulated by the Loads and Resources Subcommittee as outlined in the building block planning reserve margin section of this report. With the applicable building block guideline applied as a reserve margin requirement to each zone, the power supply margin (see table below) is greater than or equal to zero for all zones through 2008. Beginning in 2009, insufficient resource capacity and transmission in the south and possibly the effect of a transmission constraint on exports from the Northwest cause four sub-regions to become deficit. For example, the total deficit in the sub-regions in 2009 is approximately 2,300 MW and the deficit grows to approximately 3,600 MW in 2010.

**Power Supply Margin (MW) by Sub-Region for Case #1**

| Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|
| Canada | 2,250 | 2,084 | 1,761 | 1,487 | 1,246 | 935 | 593 | 322 | -158 |
| Northwest | 8,038 | 7,615 | 7,303 | 6,864 | 6,413 | 5,830 | 5,422 | 4,979 | 4,521 |
| Basin | 0 | 0 | 0 | -231 | -537 | -920 | -1,248 | -1,628 | -1,849 |
| Rockies | 0 | -44 | 0 | -154 | -502 | -851 | -1,241 | -1,653 | -2,045 |
| Desert SW | 0 | -944 | -1,829 | -2,956 | -4,016 | -5,042 | -6,037 | -7,091 | -8,065 |
| No. CA | 0 | -26 | 0 | -488 | -984 | -1,488 | -1,970 | -2,484 | -3,084 |
| So. CA/MX | 0 | -1,206 | -1,714 | -2,494 | -3,341 | -4,093 | -4,992 | -5,895 | -6,934 |
| Surplus | 10,288 | 9,699 | 9,064 | 8,351 | 7,659 | 6,765 | 6,015 | 5,301 | 4,521 |
| Deficit | 0 | -2,220 | -3,543 | -6,322 | -9,380 | -12,394 | -15,487 | -18,752 | -22,135 |

**Count of Surplus, Balanced, and Deficit zones in Case #1**

| Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|
| Canada | 2 : 0 : 0 | 2 : 0 : 0 | 2 : 0 : 0 | 2 : 0 : 0 | 1 : 0 : 1 | 1 : 0 : 1 | 1 : 0 : 1 | 1 : 0 : 1 | 1 : 0 : 1 |
| Northwest | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 |
| Basin | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 3 : 1 | 0 : 3 : 1 | 0 : 3 : 1 | 0 : 3 : 1 | 0 : 3 : 1 | 0 : 2 : 2 |
| Rockies | 0 : 3 : 0 | 0 : 2 : 1 | 0 : 3 : 0 | 0 : 2 : 1 | 0 : 2 : 1 | 0 : 1 : 2 | 0 : 1 : 2 | 0 : 1 : 2 | 0 : 1 : 2 |
| Desert SW | 0 : 6 : 0 | 0 : 3 : 3 | 0 : 3 : 3 | 0 : 3 : 3 | 0 : 3 : 3 | 0 : 3 : 3 | 0 : 3 : 3 | 0 : 3 : 3 | 0 : 3 : 3 |
| No. CA | 0 : 4 : 0 | 0 : 3 : 1 | 0 : 4 : 0 | 0 : 3 : 1 | 0 : 3 : 1 | 0 : 2 : 2 | 0 : 2 : 2 | 0 : 2 : 2 | 0 : 2 : 2 |
| So. CA/MX | 0 : 4 : 0 | 1 : 2 : 1 | 1 : 1 : 2 | 0 : 1 : 3 | 0 : 1 : 3 | 0 : 1 : 3 | 0 : 1 : 3 | 0 : 1 : 3 | 0 : 1 : 3 |

The "count" table indicates that in 2009 one zone in the Rockies sub-region, three zones in the Desert Southwest sub-region, one zone in the northern California sub-region and one zone in the southern California/Mexico are deficit.

The data and the model's solution method do not allow a precise determination of which particular zone or zones would actually be deficit. The issue of which zones, or which sub-regions are deficit is compounded by the absence of surplus capacity in the south and unused transfer capability between the southern sub-regions. The solution arrived at in the SAM calculation is only an estimation of which zones or sub-regions would be impacted first.

The "count" table also indicates that the Canada sub-region has a deficient zone even when the entire sub-region is not deficit due to a west-to-east transmission constraint between British Columbia and Alberta.

**Case #2 – Winter Modeling Building Block Reserve Guideline**

| Resource Parameters | |
|---|---|
| Existing Generation | Included |
| Class 1 Additions | Included |
| Class 2 Additions | Excluded |
| **Outages and De-rates** | |
| Adverse Hydro | Yes |
| Scheduled Maintenance | Yes |

| Demand/Load Parameters | |
|---|---|
| Firm Demand | Included |
| Non-firm Demand | Included |
| Reserve Margin | Building Block |
| Study Month | December |
| Temperature Event | No |
| Transfer Capability | Restricted |

This case models the building block reserve guideline, but under winter conditions. With the applicable building block guideline applied as a reserve margin requirement to each zone, the power supply margin is greater than or equal to zero for all zones, with the exception of Canada, throughout the entire study period. Beginning in 2008 a transmission constraint between the Northwest and British Columbia triggered a deficit condition in the Canada sub-region.

**Power Supply Margin (MW) by Sub-Region for Case #2**

| Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|
| Canada | -56 | -381 | -801 | -1,007 | -1,253 | -1,594 | -1,955 | -2,275 | -2,803 |
| Northwest | 10,652 | 11,295 | 9,659 | 9,090 | 8,581 | 7,786 | 7,133 | 6,539 | 6,000 |
| Basin | 351 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Rockies | 1,800 | 1,378 | 2,056 | 1,800 | 1,368 | 1,042 | 856 | 554 | 235 |
| Desert SW | 15,170 | 15,227 | 15,206 | 14,696 | 14,211 | 13,049 | 11,798 | 11,801 | 11,679 |
| No. CA | 8,058 | 8,307 | 8,040 | 7,340 | 6,979 | 6,570 | 5,764 | 5,009 | 3,712 |
| So. CA/MX | 4,552 | 2,944 | 2,733 | 2,403 | 2,597 | 2,593 | 2,529 | 2,423 | 2,247 |
| Surplus | 40,583 | 39,151 | 37,693 | 35,329 | 33,735 | 31,040 | 28,081 | 26,326 | 23,872 |
| Deficit | -56 | -381 | -801 | -1,007 | -1,253 | -1,594 | -1,955 | -2,275 | -2,803 |

**Count of Surplus, Balanced, and Deficit zones in Case #2**

| Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|
| Canada | 0 : 1 : 1 | 0 : 1 : 1 | 0 : 1 : 1 | 0 : 1 : 1 | 0 : 1 : 1 | 0 : 1 : 1 | 0 : 1 : 1 | 0 : 1 : 1 | 0 : 1 : 1 |
| Northwest | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 |
| Basin | 1 : 3 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 |
| Rockies | 2 : 1 : 0 | 3 : 0 : 0 | 3 : 0 : 0 | 3 : 0 : 0 | 3 : 0 : 0 | 2 : 1 : 0 | 2 : 1 : 0 | 1 : 2 : 0 | 1 : 2 : 0 |
| Desert SW | 5 : 1 : 0 | 6 : 0 : 0 | 5 : 1 : 0 | 5 : 1 : 0 | 5 : 1 : 0 | 4 : 2 : 0 | 3 : 3 : 0 | 3 : 3 : 0 | 3 : 3 : 0 |
| No. CA | 2 : 2 : 0 | 3 : 1 : 0 | 3 : 1 : 0 | 3 : 1 : 0 | 3 : 1 : 0 | 3 : 1 : 0 | 3 : 1 : 0 | 3 : 1 : 0 | 3 : 1 : 0 |
| So. CA/MX | 4 : 0 : 0 | 2 : 2 : 0 | 2 : 2 : 0 | 2 : 2 : 0 | 2 : 2 : 0 | 2 : 2 : 0 | 2 : 2 : 0 | 2 : 1 : 1 | 2 : 1 : 1 |

The "count" table indicates that only one of the two zones in the Canada sub-region became deficit. This is due to a transmission constraint that limits imports from the Northwest into British Columbia. Both Canadian zones have load requirements that exceed their generation capability and the SAM solution method allows British Columbia to have first rights to the imports to serve their increasing load.

The situation with the Southern California/Mexico sub-region is more straightforward. Beginning in 2015 Mexico (CFE) has a load requirement that is higher than the sum of their internal resources and their import capability from Southern California.

**Case #3 – Summer Modeling Building Block with Class 2 Resources**

| Resource Parameters | |
|---|---|
| Existing Generation | Included |
| Class 1 Additions | Included |
| Class 2 Additions | Included |
| **Outages and De-rates** | |
| Adverse Hydro | Yes |
| Scheduled Maintenance | Yes |

| Demand/Load Parameters | |
|---|---|
| Firm Demand | Included |
| Non-firm Demand | Included |
| Reserve Margin | Building Block |
| Study Month | July |
| Temperature Event | No |
| Transfer Capability | Restricted |

This case is the same as Case #1 but also includes the Class 2 resource changes. The addition of the Class 2 resources eliminates the deficit in the Canada sub-region, and delays the deficit in the other sub-regions until at least 2011. The 5 MW deficit in the Rockies sub-region should not be an issue of concern since the deficient zone may be able to import additional MW through its DC tie to the east.

**Power Supply Margin (MW) by Sub-Region for Case #3**

| Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|
| Canada | 2,250 | 2,119 | 1,846 | 2,022 | 1,781 | 1,470 | 1,128 | 915 | 575 |
| Northwest | 9,078 | 8,064 | 7,866 | 7,536 | 7,085 | 6,503 | 6,094 | 5,595 | 5,000 |
| Basin | 0 | 0 | 0 | 0 | -289 | -759 | -1,087 | -1,476 | -1,762 |
| Rockies | 0 | 0 | 0 | -5 | -377 | -724 | -1,114 | -1,526 | -1,918 |
| Desert SW | 0 | 0 | 237 | -1,225 | -3,330 | -4,829 | -5,976 | -7,091 | -8,065 |
| No. CA | 0 | 0 | 0 | 0 | 0 | -413 | -893 | -1,397 | -1,929 |
| So. CA/MX | 0 | 131 | 87 | -270 | -528 | -796 | -1,533 | -2,369 | -3,408 |
| Surplus | 11,328 | 10,314 | 10,035 | 9,558 | 8,866 | 7,973 | 7,222 | 6,510 | 5,575 |
| Deficit | 0 | 1 | 2 | -1,500 | -4,524 | -7,521 | -10,602 | -13,859 | -17,083 |

**Count of Surplus, Balanced, and Deficit zones in Case #3**

| Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|
| Canada | 2 : 0 : 0 | 2 : 0 : 0 | 2 : 0 : 0 | 2 : 0 : 0 | 2 : 0 : 0 | 2 : 0 : 0 | 1 : 0 : 1 | 1 : 0 : 1 | 1 : 0 : 1 |
| Northwest | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 |
| Basin | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 3 : 1 | 0 : 3 : 1 | 0 : 3 : 1 | 0 : 3 : 1 | 0 : 3 : 1 |
| Rockies | 0 : 3 : 0 | 0 : 2 : 1 | 0 : 2 : 1 | 0 : 2 : 1 | 0 : 2 : 1 | 0 : 2 : 1 | 0 : 1 : 2 | 0 : 1 : 2 | 0 : 1 : 2 |
| Desert SW | 0 : 6 : 0 | 0 : 6 : 0 | 1 : 4 : 1 | 0 : 4 : 2 | 0 : 3 : 3 | 0 : 3 : 3 | 0 : 3 : 3 | 0 : 3 : 3 | 0 : 3 : 3 |
| No. CA | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 3 : 1 | 0 : 3 : 1 | 0 : 2 : 2 | 0 : 2 : 2 |
| So. CA/MX | 0 : 4 : 0 | 1 : 2 : 1 | 1 : 3 : 0 | 0 : 2 : 2 | 0 : 2 : 2 | 0 : 2 : 2 | 0 : 2 : 2 | 0 : 1 : 3 | 0 : 1 : 3 |

The "count" table indicates that the Class 2 additions delay the capacity deficiency in the Rockies, Desert Southwest, and Southern California/Mexico. However, there are deficit zones within those sub-regions. This condition is caused by transmission constraints within the sub-region that are preventing surplus capacity from reaching the deficit zone. The Class 2 additions in the Canada sub-region eliminate the capacity shortage for the entire sub-region but there is still a deficit zone within the sub-region.

**Case #4 – Winter Modeling Building Block with Class 2 Resources**

| Resource Parameters | |
|---|---|
| Existing Generation | Included |
| Class 1 Additions | Included |
| Class 2 Additions | Included |
| **Outages and De-rates** | |
| Adverse Hydro | Yes |
| Scheduled Maintenance | Yes |

| Demand/Load Parameters | |
|---|---|
| Firm Demand | Included |
| Non-firm Demand | Included |
| Reserve Margin | Building Block |
| Study Month | December |
| Temperature Event | No |
| Transfer Capability | Restricted |

This case is the same as Case #2 but also includes the Class 2 resource changes. The addition of the Class 2 resources in the Canada sub-region delays the resource deficiency by one year until 2009.

**Power Supply Margin (MW) by Sub-Region for Case #4**

| Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|
| Canada | 0 | -296 | -716 | -472 | -718 | -1,059 | -1,420 | -1,706 | -2,043 |
| Northwest | 10,779 | 13,483 | 13,447 | 11,624 | 10,377 | 8,769 | 8,018 | 7,388 | 6,648 |
| Basin | 351 | 66 | 66 | 0 | 0 | 0 | 0 | 0 | 0 |
| Rockies | 2,108 | 1,593 | 2,218 | 1,929 | 1,630 | 1,111 | 983 | 682 | 365 |
| Desert SW | 15,170 | 15,390 | 15,243 | 15,161 | 15,275 | 14,973 | 13,132 | 12,512 | 11,706 |
| No. CA | 8,785 | 9,119 | 9,143 | 9,143 | 9,014 | 8,812 | 8,618 | 8,420 | 8,230 |
| So. CA/MX | 4,552 | 3,773 | 2,944 | 2,944 | 2,944 | 2,944 | 2,944 | 2,929 | 2,366 |
| Surplus | 41,746 | 43,424 | 43,061 | 40,801 | 39,240 | 36,608 | 33,696 | 31,930 | 29,316 |
| Deficit | 0 | -296 | -716 | -472 | -718 | -1,059 | -1,420 | -1,706 | -2,043 |

**Count of Surplus, Balanced, and Deficit zones in Case #4**

| Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|
| Canada | 0 : 2 : 0 | 0 : 1 : 1 | 0 : 1 : 1 | 0 : 1 : 1 | 0 : 1 : 1 | 0 : 1 : 1 | 0 : 1 : 1 | 0 : 1 : 1 | 0 : 1 : 1 |
| Northwest | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 |
| Basin | 1 : 3 : 0 | 1 : 3 : 0 | 1 : 3 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 |
| Rockies | 2 : 1 : 0 | 3 : 0 : 0 | 3 : 0 : 0 | 3 : 0 : 0 | 3 : 0 : 0 | 3 : 0 : 0 | 2 : 1 : 0 | 2 : 1 : 0 | 1 : 2 : 0 |
| Desert SW | 5 : 1 : 0 | 6 : 0 : 0 | 6 : 0 : 0 | 5 : 1 : 0 | 5 : 1 : 0 | 5 : 1 : 0 | 4 : 2 : 0 | 3 : 3 : 0 | 3 : 2 : 1 |
| No. CA | 2 : 2 : 0 | 3 : 1 : 0 | 3 : 1 : 0 | 3 : 1 : 0 | 3 : 1 : 0 | 3 : 1 : 0 | 3 : 1 : 0 | 3 : 1 : 0 | 3 : 1 : 0 |
| So. CA/MX | 4 : 0 : 0 | 4 : 0 : 0 | 2 : 2 : 0 | 2 : 2 : 0 | 2 : 2 : 0 | 2 : 2 : 0 | 2 : 2 : 0 | 2 : 1 : 1 | 2 : 1 : 1 |

The "count" table indicates that although one of the two zones in the Canada sub-region remains deficit the addition of the Class 2 resources does delay the deficiency by one year. The Class 2 additions in the Southern California/Mexico sub-region do not have any effect on the deficient zone within that sub-region as the Mexico (CFE) zone still has a load requirement that is higher than the sum of their internal resources and their import capability from Southern California.

**Case #5 – Summer Modeling with 15% Demand Escalation**

| Resource Parameters | |
|---|---|
| Existing Generation | Included |
| Class 1 Additions | Included |
| Class 2 Additions | Excluded |
| **Outages and De-rates** | |
| Adverse Hydro | Yes |
| Scheduled Maintenance | Yes |

| Demand/Load Parameters | |
|---|---|
| Firm Demand | Included |
| Non-firm Demand | Included |
| Reserve Margin | 15% |
| Study Month | July |
| Temperature Event | No |
| Transfer Capability | Restricted |

This case models an assumed 15% planning reserve margin for each zone. It has no relationship to the building block calculation but was included to provide a partial benchmark comparison to previous PSA results for this case. The definition of which resource additions are included is different than last year's PSA so a direct comparison to last year's assessment is not appropriate. 15% is a planning margin used by some control areas in WECC and is one end of the range of 15-17% in the complex resource adequacy requirements for most of California. With the demand forecasts for each zone escalated by 15%, the power supply margin is greater than or equal to zero for all zones through 2008. After 2008, insufficient resource capacity in the south and the effect of transmission constraints cause multiple zones in the south to become deficit.

**Power Supply Margin (MW) by Sub-Region for Case #5**

| Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|
| Canada | 1,965 | 1,790 | 1,458 | 1,177 | 890 | 436 | 43 | -284 | -777 |
| Northwest | 8,406 | 7,064 | 6,747 | 6,301 | 5,882 | 5,423 | 5,050 | 4,649 | 4,185 |
| Basin | 0 | 0 | -73 | -507 | -820 | -1,210 | -1,544 | -1,864 | -2,142 |
| Rockies | 0 | -313 | -172 | -255 | -605 | -956 | -1,348 | -1,765 | -2,160 |
| Desert SW | 0 | -626 | -1,366 | -2,618 | -3,733 | -4,707 | -5,764 | -6,832 | -7,799 |
| No. CA | 0 | 0 | 0 | -111 | -601 | -1,098 | -1,573 | -2,152 | -2,693 |
| So. CA/MX | 0 | -438 | -1,069 | -1,948 | -2,722 | -3,514 | -4,329 | -5,204 | -6,233 |
| Surplus | 10,371 | 8,855 | 8,205 | 7,478 | 6,772 | 5,859 | 5,092 | 4,649 | 4,185 |
| Deficit | 0 | -1,377 | -2,680 | -5,439 | -8,481 | -11,485 | -14,559 | -18,101 | -21,803 |

**Count of Surplus, Balanced, and Deficit zones in Case #5**

| Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|
| Canada | 2 : 0 : 0 | 2 : 0 : 0 | 2 : 0 : 0 | 1 : 0 : 1 | 1 : 0 : 1 | 1 : 0 : 1 | 1 : 0 : 1 | 1 : 0 : 1 | 1 : 0 : 1 |
| Northwest | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 | 1 : 2 : 0 |
| Basin | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 3 : 1 | 0 : 3 : 1 | 0 : 3 : 1 | 0 : 3 : 1 | 0 : 3 : 1 | 0 : 2 : 2 | 0 : 2 : 2 |
| Rockies | 0 : 3 : 0 | 0 : 2 : 1 | 0 : 2 : 1 | 0 : 2 : 1 | 0 : 2 : 1 | 0 : 1 : 2 | 0 : 1 : 2 | 0 : 1 : 2 | 0 : 1 : 2 |
| Desert SW | 0 : 6 : 0 | 0 : 4 : 2 | 0 : 3 : 3 | 0 : 3 : 3 | 0 : 3 : 3 | 0 : 3 : 3 | 0 : 3 : 3 | 0 : 3 : 3 | 0 : 3 : 3 |
| No. CA | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 4 : 0 | 0 : 3 : 1 | 0 : 3 : 1 | 0 : 2 : 2 | 0 : 2 : 2 | 0 : 2 : 2 | 0 : 2 : 2 |
| So. CA/MX | 0 : 4 : 0 | 1 : 2 : 1 | 1 : 2 : 1 | 0 : 1 : 3 | 0 : 1 : 3 | 0 : 1 : 3 | 0 : 1 : 3 | 0 : 1 : 3 | 0 : 1 : 3 |

## Temperature Events – Cases 6 Through 11

The impacts of severe summer and winter temperature events were examined in Cases 6 - 11. These cases, unlike Cases 1 - 5, looked only at a single season, summer 2010 or winter 2010-11. Because they were testing the impact of severe unexpectedly high or low temperatures, they were tested only against the reserve margin that would minimally be maintained in actual operating circumstances. This margin includes the first two building blocks, for contingencies and for regulation, and excludes the components for additional forced outages and for 1-in-10 weather events. The additional assessments are not directly comparable to the first five cases.

The WECC control areas were asked to report their load sensitivity to temperature (MW per degree Fahrenheit) for both summer and winter, the temperatures upon which their reported 1-in-2 demand forecasts were based and their temperature extremes. Historical temperature data for Western load centers was developed last year for the period 1990 to 2004 by a consultant at Lawrence Berkeley National Laboratory (LBL). The analysis used the historical weather and load data to build seasonal "temperature event" profiles for each control area for the chosen cases. An example of the calculation is given in Attachment 4.

Unlike last year's PSA, the extreme temperature analysis in Cases 6 - 11 did not attempt to replicate temperature conditions from a specific date, and juxtapose those conditions on a future load forecast. Instead, a statistical process was used to convert load forecasts to allow the study of different temperature patterns. A separate temperature sensitivity case was created to examine the impacts of the temperature pattern experienced on July 24, 2006. This was accomplished by comparing the actual demand of July 24$^{th}$ to the forecasted peak demand of July 2006. This percentage increase was applied to the demand forecasted for July 2010, and compared to the resources anticipated to be available at that time.

Two cases focused on the temperature event of July 24, 2006 applied to the future year loads. The other four cases focused on more localized and more likely weather stresses, two for the summer and two for the winter. The cases are summarized below.

**Table 10 – Temperature Sensitivity Description**

| Temperature Sensitivities: Modified Building Blocks - 2010 only | | | |
|---|---|---|---|
| **Case** | **Season** | **New Resources** | **Temperature Definition** |
| 6 | Summer | Class 1 | July 24, 2006 temperature, 2010 demand |
| 7 | Summer | Classes 1+2 | July 24, 2006 temperature, 2010 demand |
| 8 | Summer | Class 1 | Calif., Ariz., S. Nev.: 1-in-20<br>Rest of West: 1-in-10 |
| 9 | Summer | Classes 1+2 | Calif., Ariz., S. Nev.: 1-in-20<br>Rest of West: 1-in-10 |
| 10 | Winter | Class 1 | Canada, NW, Basin, N. Calif.: 1-in-20<br>Rest of West: 1-in-10 |
| 11 | Winter | Classes 1+2 | Canada, NW, Basin, N. Calif.: 1-in-20<br>Rest of West: 1-in-10 |

In each of the temperature sensitivity cases a study of MW change per degree was done to determine the increase in demand associated with increasing the temperature from a 1-in-2 condition to a 1-in-20 temperature condition. The increase in demand associated with each of the temperature sensitivity cases is shown in Table 11.

**Table 11 - Load Requirement Increase (MW) for Temperature Sensitivity Cases**

| | Case | | | | | |
|---|---|---|---|---|---|---|
| | July 24, 2006 temperature, 2010 demand Class 1 | July 24, 2006 temperature, 2010 demand Class 1 & 2 | Summer Calif., Ariz., S. Nev.: 1-in-20 Class 1 | Summer Calif., Ariz., S. Nev.: 1-in-20 Class 1 & 2 | Winter Canada, NW, Basin, N. Calif.: 1-in-20 Class 1 | Winter Canada, NW, Basin, N. Calif.: 1-in-20 Class 1 & 2 |
| Sub-Region | 6 | 7 | 8 | 9 | 10 | 11 |
| Canada | 910 | 910 | 0 | 0 | 179 | 179 |
| Northwest | 4,565 | 4,565 | 0 | 0 | 476 | 476 |
| Basin | 319 | 319 | 0 | 0 | 88 | 88 |
| Rockies | -303 | -303 | 0 | 0 | 0 | 0 |
| Desert Southwest | 1,022 | 1,022 | 362 | 362 | 0 | 0 |
| No. California | 3,010 | 3,010 | 700 | 700 | 85 | 85 |
| So. California/Mexico | 4,118 | 4,118 | 989 | 989 | 0 | 0 |

Table 12 contains the resource surplus or deficit under the winter or summer extreme peak conditions of year 2010 for each of the temperature sensitivity cases. It is important to note that these results can not be compared to the results from cases 1–5 due to the differences in the reserve components, contingency and regulation in cases 6–11 and all of the building block elements in cases 1–5.

**Table 12 - Resource Surplus/Deficit (MW)**

| | Case | | | | | |
|---|---|---|---|---|---|---|
| | July 24, 2006 temperature, 2010 demand Class 1 | July 24, 2006 temperature, 2010 demand Class 1 & 2 | Summer Calif., Ariz., S. Nev.: 1-in-20 Class 1 | Summer Calif., Ariz., S. Nev.: 1-in-20 Class 1 & 2 | Winter Canada, NW, Basin, N. Calif.: 1-in-20 Class 1 | Winter Canada, NW, Basin, N. Calif.: 1-in-20 Class 1 & 2 |
| Sub-Region | 6 | 7 | 8 | 9 | 10 | 11 |
| Canada | 1,698 | 1,783 | 2,119 | 2,119 | -275 | -190 |
| Northwest | 4,671 | 4,855 | 9,204 | 11,757 | 14,301 | 16,668 |
| Basin | 0 | 0 | 0 | 0 | 0 | 436 |
| Rockies | 0 | 0 | 0 | 0 | 2,841 | 2,968 |
| Desert Southwest | -359 | -91 | 3,103 | 5,302 | 15,258 | 16,313 |
| No. California | -1,981 | -904 | 0 | 0 | 8,897 | 9,143 |
| So. California/Mexico | -4,740 | -1,824 | 246 | 246 | 2,944 | 4,205 |
| Surplus | 6,369 | 6,639 | 14,672 | 19,424 | 44,241 | 49,733 |
| Deficit | -7,080 | -2,819 | 0 | 0 | -275 | -190 |

## Summary of Assessment Results by Sub-region

For each of the sub-regions a graph and two matrices are presented. The graph presents the sub-region's power supply margin through 2016 using three different sets of assumptions. A summary description of each case is given below. The first matrix shows the planned resource additions, by class, and the second matrix shows the planned additions by fuel type. The fuel type matrix, however, only includes class 1 and class 2 resources. Note that the scaling is not consistent from graph to graph in order to clearly show the magnitudes of the changes in each graph. Additional details of the study results (including more tables and graphs) are presented in Attachment 2.

To the extent that control areas are successful in adding Class 3 resources and/or transmission, the supply margin pictures may improve as described in the narrative for each sub-region.

In each of the Graphs 5 – 18, the following nomenclature is used.

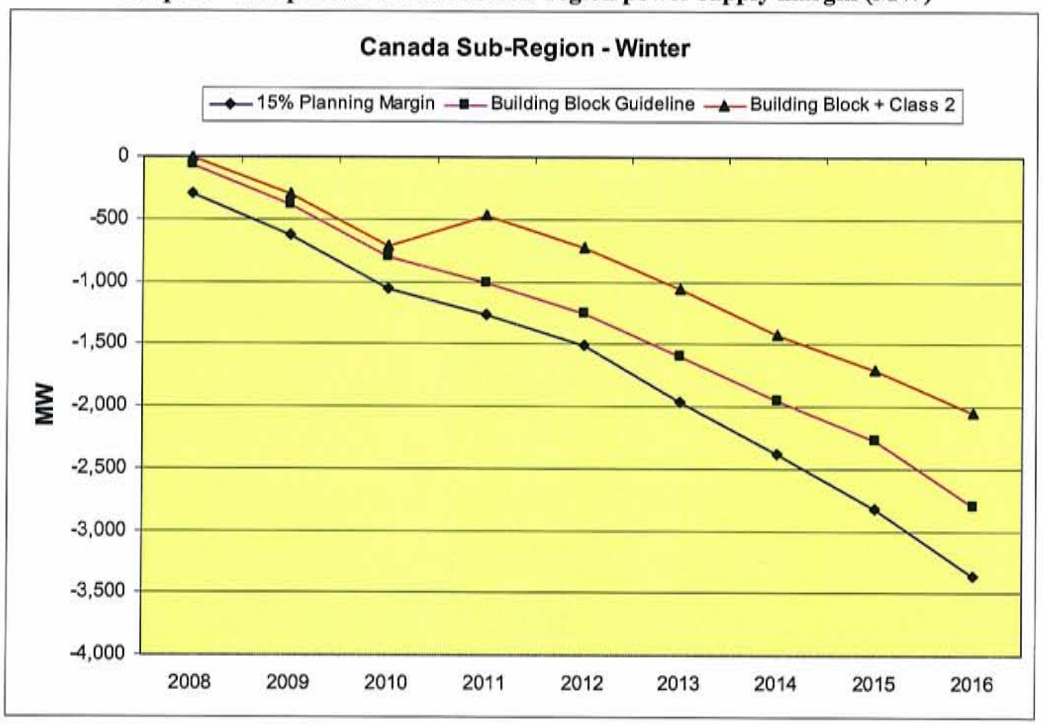
| Plot Label | Case | Reserve Requirement | Resource Additions |
|---|---|---|---|
| Building Block Guideline | 1 – Summer<br>2 – Winter | Building Block Reserve Guideline | Class 1 only |
| Building Block + Class 2 | 3 – Summer<br>4 – Winter | Building Block Reserve Guideline | Class 1 and Class 2 |
| 15% Planning Margin | 5 – Summer | 15% reserve margin | Class 1 only |

Note also that the effect of adding Class 2 resources that is shown in any particular sub-region's load-resource balance graph is often bigger than the additional Class 2 capacity shown in that sub-region's resource addition tables. This is because additions in one sub-region, if surplus to that sub-region, will be transferred to deficit sub-regions, subject to the transmission constraints in SAM. The effect of adding Class 2 resources can be spread beyond the sub-region in which they were added.

## Canada

| Sub-Region | Zones in Sub-Region |
|---|---|
| Canada | Alberta, British Columbia |

**Graph 5 - Comparison of Canada sub-region power supply margin (MW)**




The results for the winter case show that the Canada sub-region is currently in need of additional resources or additional import capability.

**Canada Planned Resources Identified by Class**

| Sub-region | Class | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Canada | 1 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5 |
| Canada | 2 | 85 | 30 | 560 | 450 | 0 | 0 | 0 | 0 | 0 | 1,125 |
| Canada | 1 & 2 | 90 | 30 | 560 | 450 | 0 | 0 | 0 | 0 | 0 | 1,130 |
| Canada | 3 | 0 | 0 | 0 | 435 | 0 | 0 | 0 | 0 | 0 | 435 |

**Canada Planned Resources Identified by Type (Class 1 and Class 2 Only)**

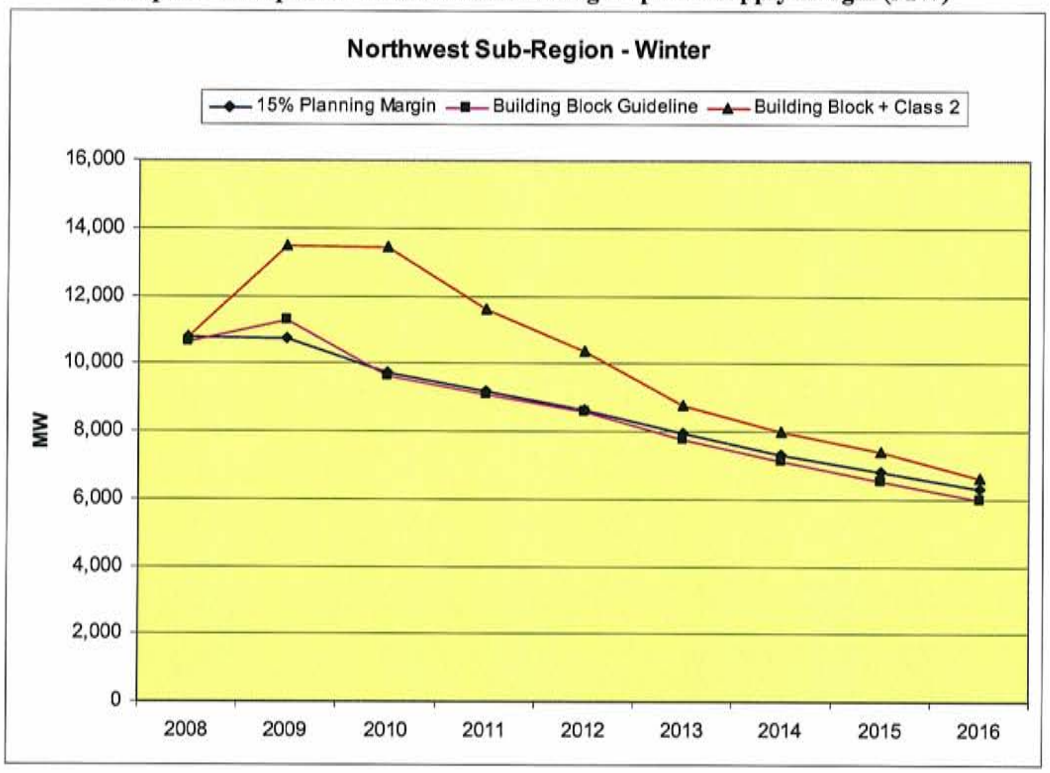
| Sub-Region | Type | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Canada | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | 5 | 30 | 560 | 0 | 0 | 0 | 0 | 0 | 0 | 595 |
| | Thermal | 85 | 0 | 0 | 450 | 0 | 0 | 0 | 0 | 0 | 535 |
| | Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

As depicted in the table, even with the addition of the Class 3 resources the sub-region is in need of additional resources and/or import capability. The reporting entities in the Canada sub-region are aware of this need. For example, in 2006 BC Hydro and Power Authority awarded 38 contracts to independent power producers (IPPs) across British Columbia totaling approximately 7,000 GWh of energy per year. These projects, most of which are projected to brought online before 2011, do not appear in any of the new resource classes because their seasonal capacity values were not reported in the 2006 L&R data submission. In Alberta, the structure of the competitive electricity market is such that generation developers respond to market signals to determine the amount, timing, location and generation type to be added. Additional generation resources are expected to appear in the future as market conditions dictate.

**Northwest**

| Sub-Region | Zones in Sub-Region |
|---|---|
| Northwest | COB, Montana, Pacific Northwest |

**Graph 6 - Comparison of Northwest sub-region power supply margin (MW)**




CAVEAT: This peak hour capacity assessment does not address the complicated energy limitations that apply to the Northwest hydro system. The consistent capacity surplus over Northwest loads, while large, is unlikely to be of the magnitude shown in the graph above.

**Northwest Planned Resources Identified by Class**

| Sub-region | Class | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Northwest | 1 | 586 | 12 | 12 | 0 | 0 | 0 | 0 | 0 | 0 | 610 |
| Northwest | 2 | 30 | 0 | 0 | 12 | 12 | 0 | 0 | 0 | 0 | 54 |
| Northwest | 1 & 2 | 616 | 12 | 12 | 12 | 12 | 0 | 0 | 0 | 0 | 664 |
| Northwest | 3 | 65 | 1,099 | 0 | 0 | 0 | 500 | 0 | 0 | 0 | 1,664 |

Note that this table indicates that several new Class 3 projects were reported that are not currently under construction or under regulatory review and are excluded for this assessment.

**Northwest Planned Resources Identified by Type (Class 1 and Class 2 Only)**

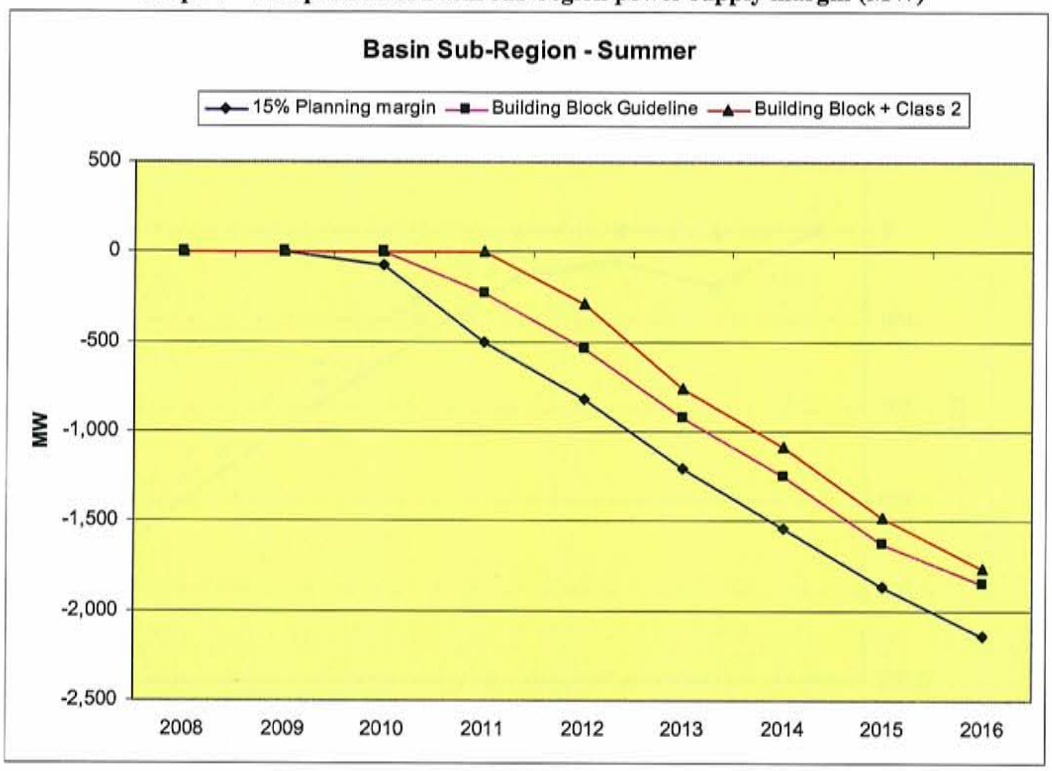
| Sub-Region | Type | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Northwest | Wind | 30 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 30 |
| | Hydro | (15) | 12 | 12 | 12 | 12 | 0 | 0 | 0 | 0 | 35 |
| | Thermal | 600 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 600 |
| | Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Refer to the attached (Attachment 6) Pacific Northwest Energy Assessment for more information.

**Basin**

| Sub-Region | Zones in Sub-Region |
|---|---|
| Basin | Idaho, No. Nevada, Utah, IPP |

**Graph 7 - Comparison of Basin sub-region power supply margin (MW)**




The load requirements for the Basin sub-region are met through 2009 or later, depending on the case. Note that the following table indicates that several new Class 3 projects were reported that are not currently under construction or under regulatory review and are excluded for this assessment. If these Class 3 projects are completed in the reported timeframes, the Basin sub-region will likely have a supply/demand balance during the study time period.

**Basin Planned Resources Identified by Class**

| Sub-region | Class | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Basin | 1 | 730 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 730 |
| Basin | 2 | 165 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 165 |
| Basin | 1 & 2 | 895 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 895 |
| Basin | 3 | 9 | 0 | 32 | 0 | 1,325 | 0 | 0 | 750 | 0 | 2,116 |

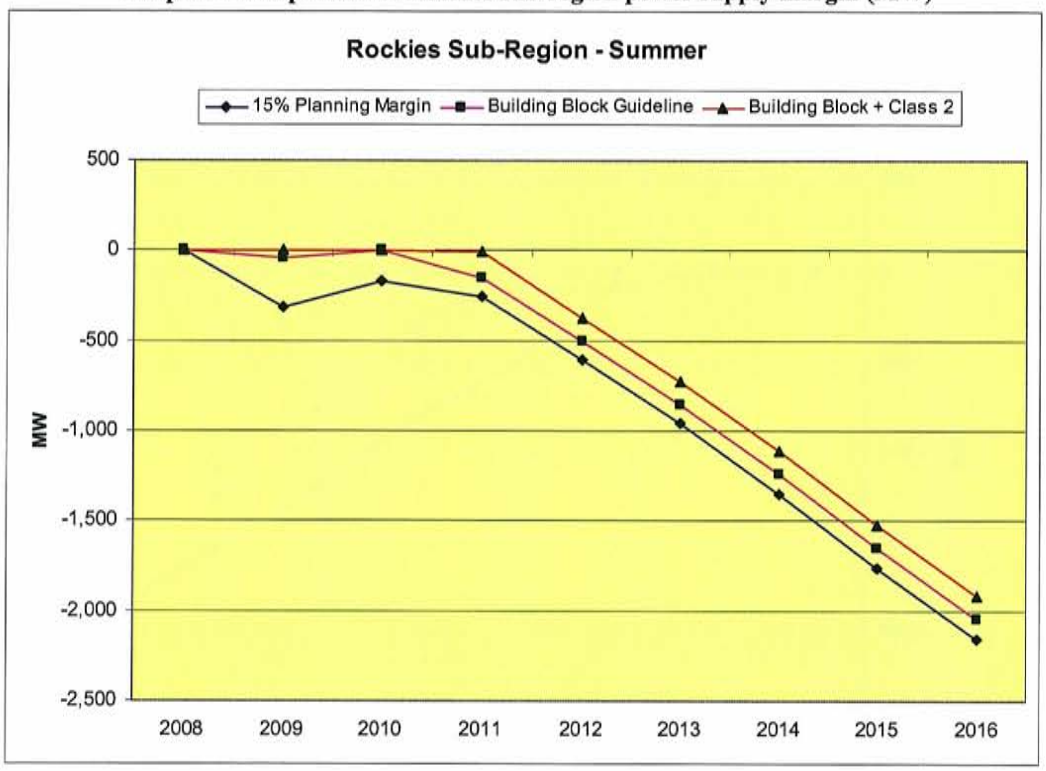
**Basin Planned Resources Identified by Type (Class 1 and Class 2 Only)**

| Sub-Region | Type | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Basin | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 |
| | Thermal | 879 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 879 |
| | Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Other | 13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 13 |

**Rockies**

| Sub-Region | Zones in Sub-Region |
|---|---|
| Rockies | Colorado-East, Colorado-West, Wyoming |

**Graph 8 - Comparison of Rockies sub-region power supply margin (MW)**




In general, the results predict that additional resources are needed beginning in 2009 in order to meet the forecasted load requirements. The Rockies sub-region is impacted by the North-South split, but has limited transmission to MAPP and SPP at its eastern borders. The effect of that interconnection was not assessed.

**Rockies Planned Resources Identified by Class**

| Sub-region | Class | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Rockies | 1 | 22 | 0 | 1,024 | 0 | 0 | 0 | 0 | 0 | 0 | 1,046 |
| Rockies | 2 | 124 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 124 |
| Rockies | 1 & 2 | 146 | 0 | 1,024 | 0 | 0 | 0 | 0 | 0 | 0 | 1,170 |
| Rockies | 3 | 138 | 500 | 0 | 385 | 600 | 600 | 0 | 0 | 0 | 2,223 |

**Rockies Planned Resources Identified by Type (Class 1 and Class 2 Only)**

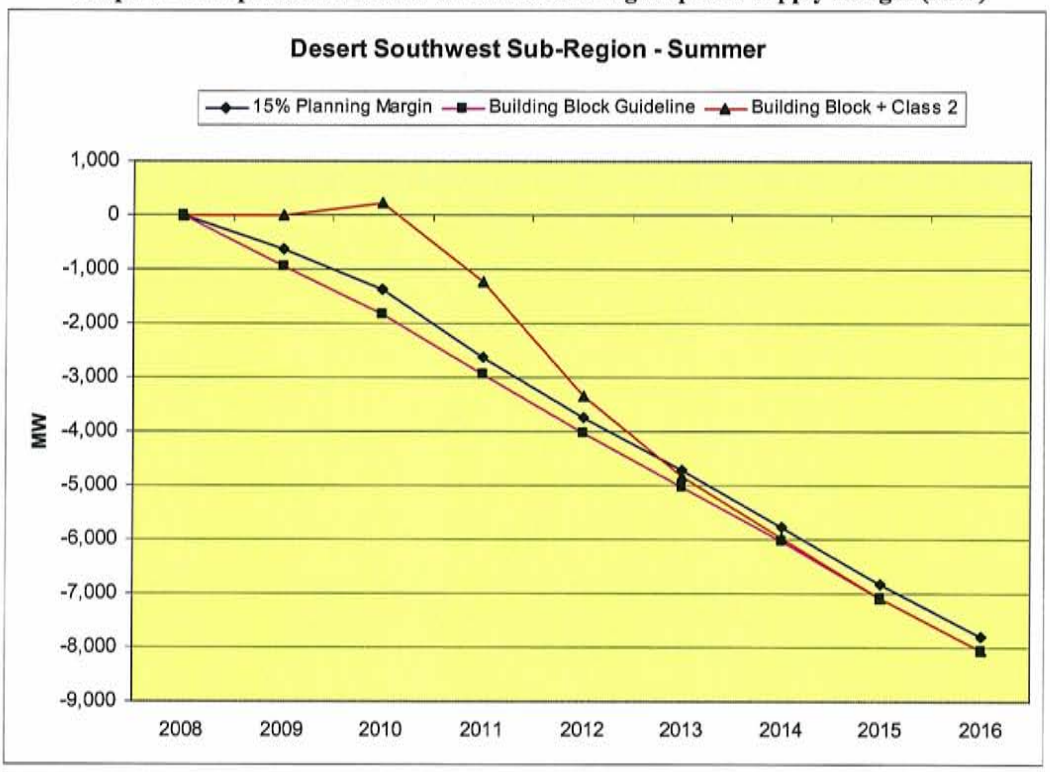
| Sub-Region | Type | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Rockies | Wind | 8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 8 |
| | Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Thermal | 137 | 0 | 1,024 | 0 | 0 | 0 | 0 | 0 | 0 | 1,161 |
| | Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

As depicted in the table, there are several Class 3 projects that are not included in the PSA analysis. These projects are not currently under construction or submitted for regulatory review. If these Class 3 projects are completed in the reported timeframes, the Rockies sub-region would show an adequate margin for the term of the study.

**Desert Southwest**

| Sub-Region | Zones in Sub-Region |
|---|---|
| Desert SW | Arizona, IID, Four Corners, New Mexico, Palo Verde, So. Nevada |

**Graph 9 - Comparison of Desert Southwest sub-region power supply margin (MW)**




The results show that the Desert Southwest sub-region has a power supply margin equal to or greater than zero through 2008 or later, depending on the summer cases.

**Desert Southwest Planned Resources Identified by Class**

| Sub-region | Class | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Desert SW | 1 | 487 | 608 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,095 |
| Desert SW | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Desert SW | 1 & 2 | 487 | 608 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,095 |
| Desert SW | 3 | 321 | 283 | 272 | 149 | 754 | 174 | 547 | 470 | 58 | 3,028 |

**Desert Southwest Planned Resources Identified by Type (Class 1 and Class 2 Only)**

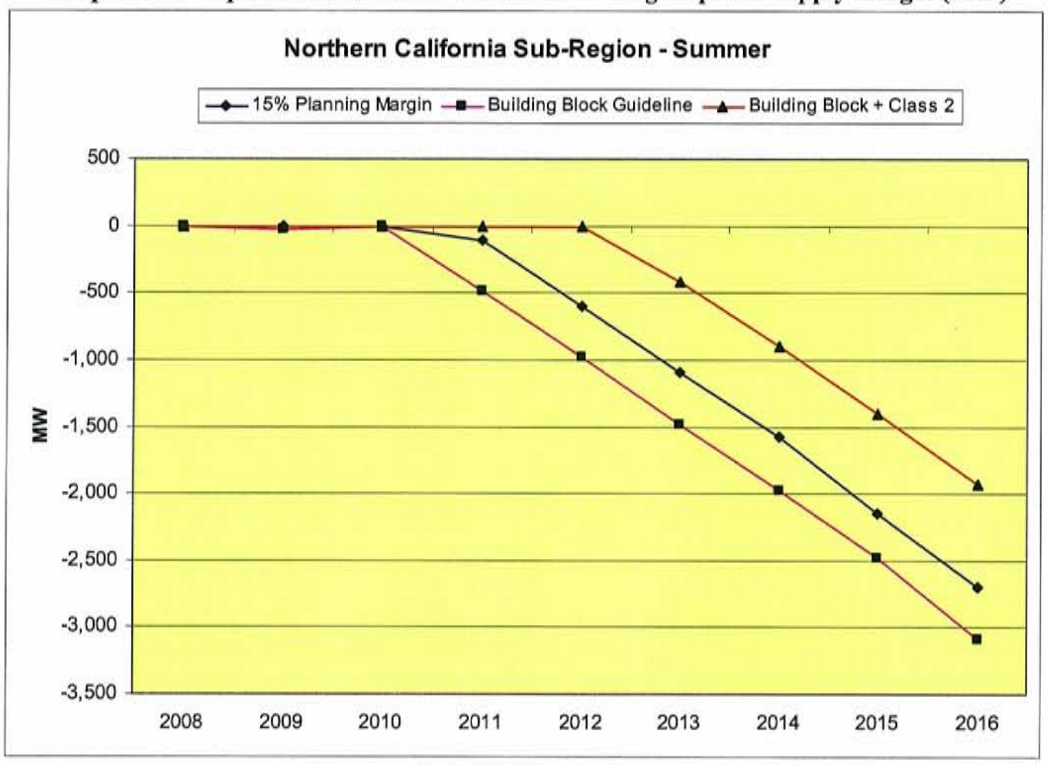
| Sub-Region | Type | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Desert SW | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Thermal | 487 | 608 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,095 |
| | Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

As depicted in the table, if the 3,000 MW of Class 3 additions are completed as reported, the Desert Southwest would still be in need of additional resources or import capability.

**Northern California**

| Sub-Region | Zones in Sub-Region |
|---|---|
| No. CA | Central CA, Northern CA, San Francisco, SMUD |

**Graph 10 - Comparison of Northern California sub-region power supply margin (MW)**




The load requirements for the Northern California sub-region are met through 2012 or later, depending on the case. The zero power supply margin in earlier years is a reflection of the transfers modeled by SAM into and out of the Northern California sub-region. This contrasts with the Southern California sub-region, which consists of zones that are less well connected to other sub-regions. These Northern California results are consistent with resource adequacy assessments conducted by California entities.

The North-South split does not affect the Northern California sub-region as early as it does Southern California and the Desert Southwest due to its proximity to the Northwest, the limited transfer capacity between Central and Southern California zones, and the dispatch method used by the model. In SAM, Northern California, is, in essence, given the first opportunity to use the imports from the Northwest, which is entirely an artifact of the model.

**Northern California Planned Resources Identified by Class**

| Sub-region | Class | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| No. CA | 1 | (5) | 482 | 48 | 0 | 0 | 0 | 0 | 0 | 0 | 525 |
| No. CA | 2 | 727 | 1,234 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,961 |
| No. CA | 1 & 2 | 722 | 1,716 | 48 | 0 | 0 | 0 | 0 | 0 | 0 | 2,486 |
| No. CA | 3 | 3,733 | 645 | 609 | 54 | 0 | 0 | 390 | 0 | 0 | 5,431 |

**Northern California Planned Resources Identified by Type (Class 1 and Class 2 Only)**

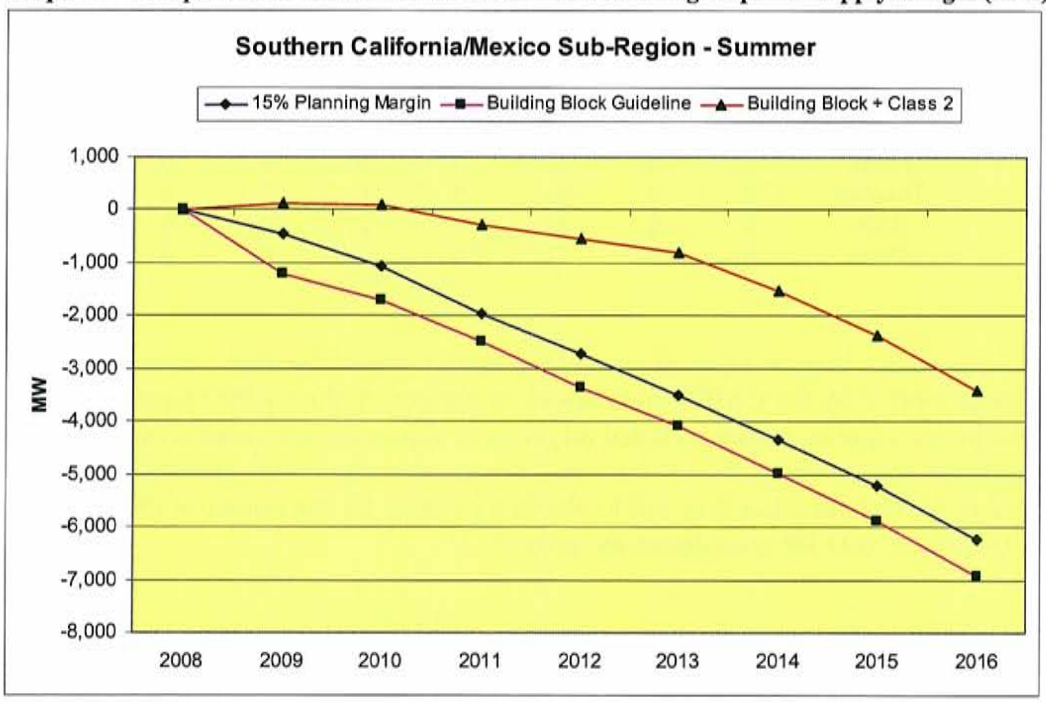
| Sub-Region | Type | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| No. CA | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Thermal | 722 | 1,716 | 48 | 0 | 0 | 0 | 0 | 0 | 0 | 2,486 |
| | Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Class 3 contains a large amount of resource in early years of the study period. The new generation additions reported by the CAISO were based on projects in the CAISO large generator interconnection queue, which included all projects requesting interconnection to the CAISO grid. A significant percentage of the projects in this queue are somewhat speculative and are either delayed or never built since they fail to obtain a contract for the output of the project, financing, or some other necessity for completing the project.

**Southern California/Mexico**

| Sub-Region | Zones in Sub-Region |
|---|---|
| So. CA/MX | CFE-Mexico, Southern CA, San Diego, LADWP |

**Graph 11 - Comparison of Southern California/Mexico sub-region power supply margin (MW)**




The results of this assessment predict that the load requirements in Southern California/Mexico can be met through 2008 with Class 1 or Class 2 resource additions. This is consistent with California's own assessment which shows Southern California needing resources earlier than Northern California. Where the power supply margin is positive, this is due to a surplus in Mexico, not Southern California. In each of the summer cases Southern California is reliant on imports from other sub-regions to meet its load requirements (see tables in Attachment 2).

Class 3 contains a large amount of resource in early years of the study period, as shown in the table below. The new generation additions reported by the CAISO were based on projects in the CAISO large generator interconnection queue, which included all projects requesting interconnection to the CAISO grid. A significant percentage of the projects in this queue are somewhat speculative and are either delayed or never built since they fail to obtain a contract for the output of the project, financing, or some other necessity for completing the project.

# APPENDIX A-5-K



**Southern California/Mexico Planned Resources Identified by Class**

| Sub-region | Class | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| So. CA/MX | 1 | 16 | 494 | 93 | 0 | 0 | 0 | 0 | 0 | 0 | 603 |
| So. CA/MX | 2 | 0 | 2,046 | 610 | 0 | 0 | 0 | 0 | 0 | 0 | 2,656 |
| So. CA/MX | 1 & 2 | 16 | 2,540 | 703 | 0 | 0 | 0 | 0 | 0 | 0 | 3,259 |
| So. CA/MX | 3 | 4,072 | 5,834 | 4,155 | 2,880 | 0 | 1,688 | 0 | 279 | 156 | 19,064 |

**Southern California/Mexico Planned Resources Identified by Type (Class 1 and Class 2 Only)**

| Sub-Region | Type | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| So.CA/MX | Wind | 0 | 12 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 12 |
| | Hydro | 16 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 16 |
| | Thermal | 0 | 2,528 | 703 | 0 | 0 | 0 | 0 | 0 | 0 | 3,231 |
| | Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

## Additional Assumptions

The following assumptions were made for this assessment:

- The input data represents demand forecasts and resource plans submitted between December 2006 and February 2007.
- Non-coincidental demands were used such that the monthly peak zonal demands are the sum of the control area peak demands for each zone.
- July data was used for the summer peak period for each year. December data was used for the winter peak period.
- This assessment assumes that the demand for a given zone is the sum of the control area customer demands within that zone. This differs from the "load requirement" concept where the load that must be served is the customer demand plus the firm exports. Under most circumstances, the application of "forced transfers" to accommodate firm exports would tend to undermine the model solution.
- Peak demands for CISO, PACE, PSC, WACM, and WALC were allocated to SAM zones based on the following ratios reported by the PCC representatives as part of their annual review. In the future, it may be desirable for those entities to report the L&R data for each zone rather than at an aggregated level which is then disaggregated for modeling purposes.

**Table 13 - Percent of Control Area Demand Allocated to Zones**

| Zones \ Control Area | CISO | PACE | PSC | WACM | WALC |
|---|---|---|---|---|---|
| Arizona | | | | | 72% |
| Colorado, East | | | 88% | 50% | |
| Colorado, West | | | 12% | 28% | |
| Idaho | | 8.2% | | | |
| New Mexico | | | | | 28% |
| Utah | | 77.3% | | | |
| Wyoming | | 14.5% | | 22% | |
| California, North | 36.0% | | | | |
| California, Central | 6.5% | | | | |
| California, South | 45.0% | | | | |
| California, San Diego | 10.0% | | | | |
| California, San Fran. | 2.5% | | | | |

- Since the goal of the study was assessing the ability of the system to meet load and not any particular economic outcome, the summary resources in each zone were all assigned the same costs (US Hydro = $5/MWH, Canadian Hydro = $6/MWH, Non-hydro = $20/MWH), with the exception of Palo Verde ($15/MWH).
- The adjustments (forced transfers) for external generation (generation in one zone owned by an LSE in another zone) that were used in the studies were for Bridger, Colstrip, Craig, Four Corners, Hayden, Hoover, Intermountain, Navajo, Palo Verde, San Juan, and San Onofre. No other adjustments were made for other joint plants or firm purchases.
- Except for the 325 MW contractual imports into New Mexico from the Southwest Power Pool (SPP), ties to the Mid-Continent Area Power Pool (MAPP) and SPP are not modeled since this

would require generation and/or demand to be associated with these external regions. Additional long term contracts that result in consistent imports or exports could be represented in the model if the Loads and Resources Subcommittee determines that this is appropriate.

- The model freely transfers resources from areas with surplus generation to deficit areas, with consideration for transfer path constraints and transmission losses. Simultaneous flows, loop flows, and other transfer restrictions are approximated by the restricted transfer limits that were used in the studies, but the model is a transport model, not a power flow model.
- The model is not intended to measure the supply margins in the individual control areas (unless the zone definition and transfer capabilities exactly match the control area). The model assumes that there are no constraints internal to a zone.

## Observations and Caveats

1. This assessment is based on the physical ability of the Interconnection to supply all loads regardless of contractual obligations. This means that the model uses economic relationships to calculate transfers between zones within the assigned limits. In reality, the ideal solutions may be difficult to duplicate in the operational environment. System operation for contract obligations and other conditions could adversely affect the availability of resources, and could impact the amount and timing of power supply deficiencies in specific zones.
2. Using non-coincidental demands tends to overstate the simultaneous demand. Preliminary studies indicate that the simultaneous combined peak demand for WECC has a variance of 1% to 3%, compared to the non-simultaneous demand.
3. Surplus generation in the Pacific Northwest zone was often stranded due to transmission limitations (see North-South split diagram on page 19 for constraint points). However, neither the summer nor the winter analysis for the Northwest sub-region captures the limitations on the ability of the hydro system to sustain output levels beyond a single hour. Because of this limitation, the reported surpluses for potential export to other sub-regions of the West are likely to be unrealistically high. Northwest entities are continuing to work on a more realistic characterization of the ability of the hydro system to meet loads and export markets.
4. There were cases where surplus resources were available, but transfer path limitations prevented the surplus from reaching the areas with deficits. Whenever an individual zone became deficit while other sub-regions had surpluses (sum of zonal surpluses/deficits were greater than zero), there were one or more transfer path limitations between the surplus area(s) and the deficit area(s).
5. The assessment results for the period beyond 2013 do not represent a realistic picture of future power supply margins, but do represent a picture of future resource needs for the given load forecast and transmission system. The addition of generation plants that are not accounted for in the current data should be expected. There is a point where the results shift from a determination of supply margin to a determination of future needs.
6. A determination that a zone has sufficient resources and imports to meet its load requirement does not necessarily mean that all of the demand centers within that zone can meet their load requirements. Transmission constraints internal to a zone may limit capacity transfers to local demand areas, leaving them without a positive margin. These transmission-constrained local

demand areas may include one or more major metropolitan areas within a zone and may include most of the total population within a zone.

7. The model assumes an optimistic efficiency where resources and transmission become immediately available as necessary to meet demand requirements. System operation to meet contract obligations and other conditions could adversely affect the availability of resources, and could impact the amount and timing of power supply deficiencies in specific zones.

## Recommendations for Future Assessments

1. The hydro generation capability in the Northwest sub-region has limitations beyond those assumed for this assessment. The seasonal operation of the coordinated hydro system is subject to dozens of parameters that accommodate the various interests in the river systems as well as physical limits on the storage capability of the system. Northwest entities are continuing to work on a more realistic characterization of the ability of the hydro system to meet loads and export markets. If the effect of these factors can be determined, they should be addressed in future assessments.

2. Future plans for the model may include conducting probabilistic or stochastic studies to study the effects of random uncertainties. This would require that the members provide additional information such as resource forced outage rates, resource operating costs, demand variations, transmission loss data and transmission wheeling costs.

3. Planned changes to the transfer path capabilities must be reflected in the model to accurately measure their effect on the results. Since they would usually directly affect the results, only changes that are highly probable should be taken into consideration.

4. The effects of fuel diversity and availability should be modeled in future assessments. The prevalence of natural gas- and coal-fired generation in WECC has raised concerns about the interdependencies of and electricity and fuel supply. Improved analyses should evaluate the impact of fuel shortages due to fuel supply interruptions or demand spikes.

5. Although an energy assessment for one zone (the Pacific Northwest) is included, expanding to other sub-regions and zones where relevant for WECC is still a goal for the future. While WECC recognizes the need for an assessment of energy supplies, it is expected that the data and manpower requirements for energy assessments would be significantly higher than for this peak hour capacity assessment. A more sophisticated model would also be needed.

# Attachment 1: Model Outline

## A. Description of Model

The "Supply Adequacy Model" (SAM) was developed by the CEC to study the balance between projected demands and resources in California and other WECC areas, taking into consideration transmission limitations between the defined zones or bubbles. The model has the capability to perform either multiple-iteration probabilistic (stochastic) studies or single-iteration deterministic studies. Per instructions from the Loads and Resources Subcommittee, all of the studies conducted for this report were deterministic. If probabilistic studies are requested in the future, it will be necessary to collect additional information from the WECC members.

For the purposes of this assessment, the WECC region is divided into the zones listed below. The zones are configured around demand centers and transmission hubs. Refer to the topology bubble diagrams for connections between zones.

| | | |
|---|---|---|
| Alberta | California, SMUD | Montana |
| Arizona | California, South | Nevada, North |
| British Columbia | CFE-Mexico | Nevada, South |
| California, Central | COB | New Mexico |
| California, IID | Colorado, East | Northwest |
| California, LADWP | Colorado, West | Palo Verde |
| California, North | Four Corners | Utah |
| California, San Diego | Idaho | Wyoming |
| Calif., San Francisco | IPP | |

The COB, Four Corners, IPP, and Palo Verde zones have no load assigned to them.

The following acronym definitions apply to this report.

| | |
|---|---|
| AZ-NM-SNV | Arizona – New Mexico – Southern Nevada |
| CA-MX | California – Mexico (CFE –WECC) |
| CFE | Comision Federal de Electricidad |
| CAISO | California Independent System Operator |
| COB | California-Oregon Border |
| CREPC | Committee on Regional Electric Power Cooperation |
| IID | Imperial Irrigation District |
| LADWP | Los Angeles Department of Water and Power |
| MAPP | Mid-Continent Area Power Pool |
| NWPP | Northwest Power Pool |
| PSC | Public Service of Colorado |
| RMPA | Rocky Mountain (Colorado – Wyoming) |
| SMUD | Sacramento Municipal Utility District |
| SPP | Southwest Power Pool |
| WACM | WAPA – Colorado / Missouri |
| WALC | WAPA – Lower Colorado |

**Model Topology**

The topology of the model is shown in the bubble diagrams on pages 48 and 49. The lines between zones are intended to represent transmission connections between the zones and the listed numbers are the transfer path capabilities as reported by the control area representatives. The model observes these maximum capabilities as it calculates the solutions for each case. These maximum capabilities represent the Restricted Transfer Capabilities (the limits that may reasonably be expected to apply under simultaneous high seasonal transmission loading conditions).

The capabilities shown in blue indicate that there are changes in transfer capability during the study period (see list below). Transfers with other regional councils such as MAPP and SPP are ignored in this assessment (with the exception of a 325 MW firm purchase in the New Mexico zone) as this would require an assumption regarding the amount of surplus or deficit generation in those councils.

For this assessment, the following transfer capability changes were represented.

- Palo Verde – Arizona, new restricted capacity of 8,010 MW west-to-east due to upgrades including series capacitors, effective May 2008.
- Palo Verde – Southern California (IID, LADWP, Southern California, San Diego), new restricted capability of 3,922 MW east to west due to PV-Devers 2 project, effective May 2009.
- Colorado East – New Mexico via Four Corners, new restricted capability of 1,529 MW north-to-south due to addition of Walenburg to Gladstone line, effective January 2007.
- New Mexico – Colorado east via Four Corners, new restricted capability of 955 MW south-to-north due to addition of Walenburg to Gladstone line, effective January 2007.
- 1,000 MW correction to increase in transfer limit from Pacific Northwest to British Columbia to 2,000 MW.

**Model Solution and Constraints**

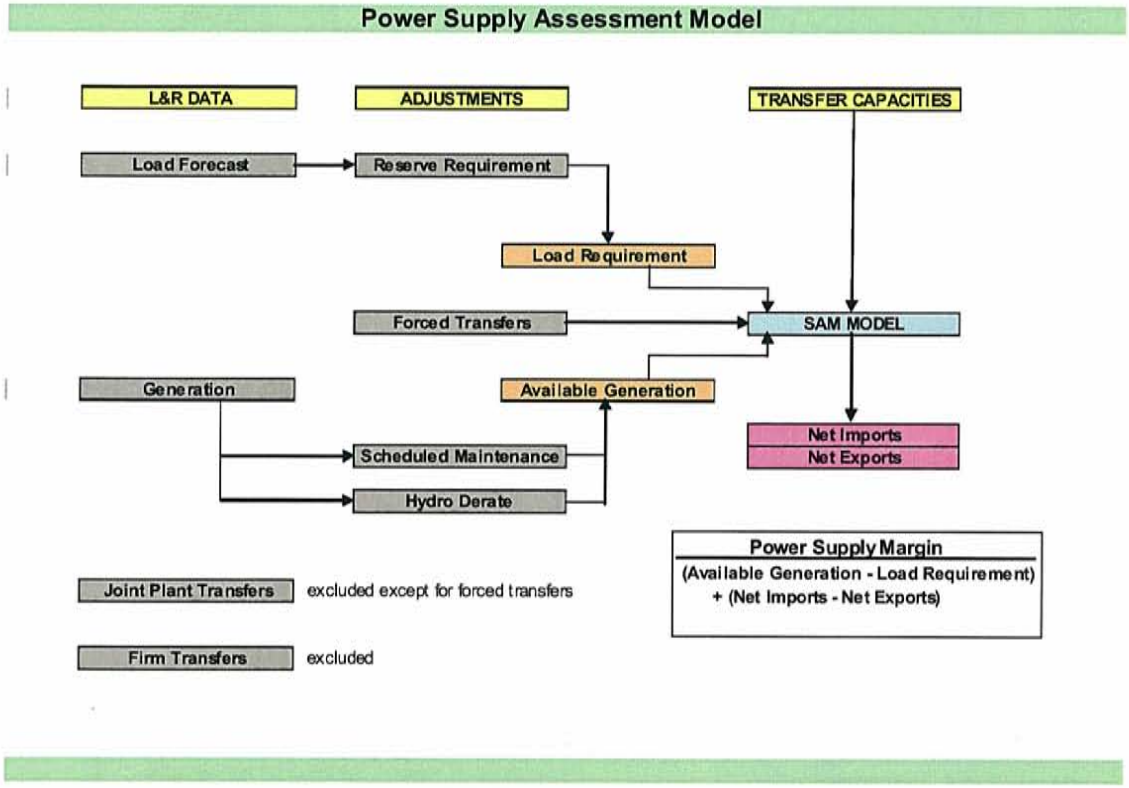
Microsoft Solver, a third-party tool included with Excel for solving constraint-based problems, is used to solve the demand/resource balance and calculate the surplus generation and transfers for each zone. The solution seeks the lowest overall resource cost subject to the following constraints:

- The demand requirements of each zone must be met (surplus >= 0); but it's possible for a zone to be deficit before solver starts
- The resource solution for each zone must be equal to or greater than zero
- The resource solution for each zone must not be greater than the available resources
- The resource solution for each zone must not be less than the minimum resource allocation

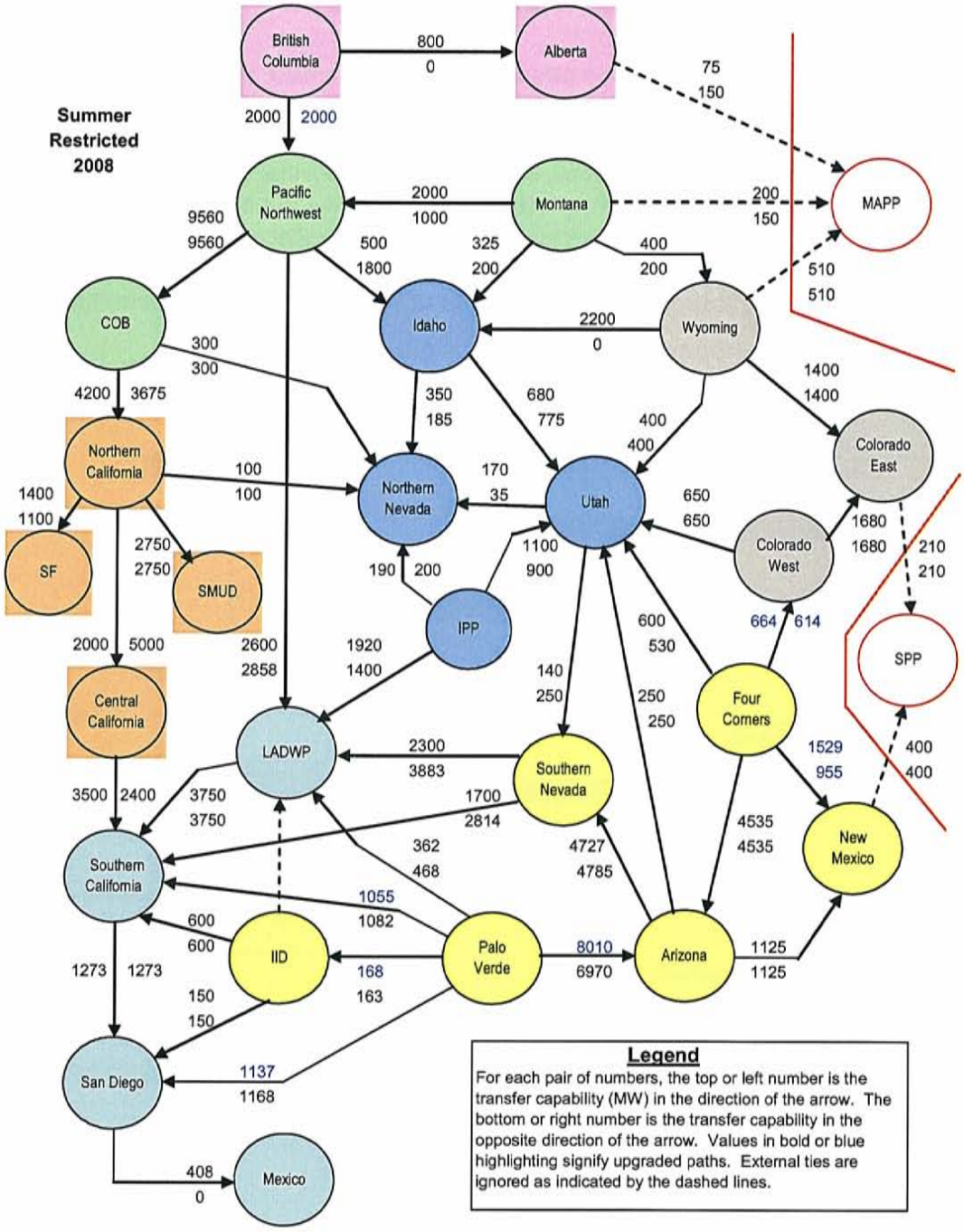
The solution uses transfers between zones to export resources from surplus zones to deficit zones. If a deficit is greater than the available transfer capability from the connected zones, then the zone will have a net deficit. The solution will also back off internal generation in a zone if a connecting zone has a surplus that is less expensive and the transfer path has available capability.

Lower cost resources such as hydro resources are given priority within a zone and as imports, to serve local load and to displace more expensive generation.

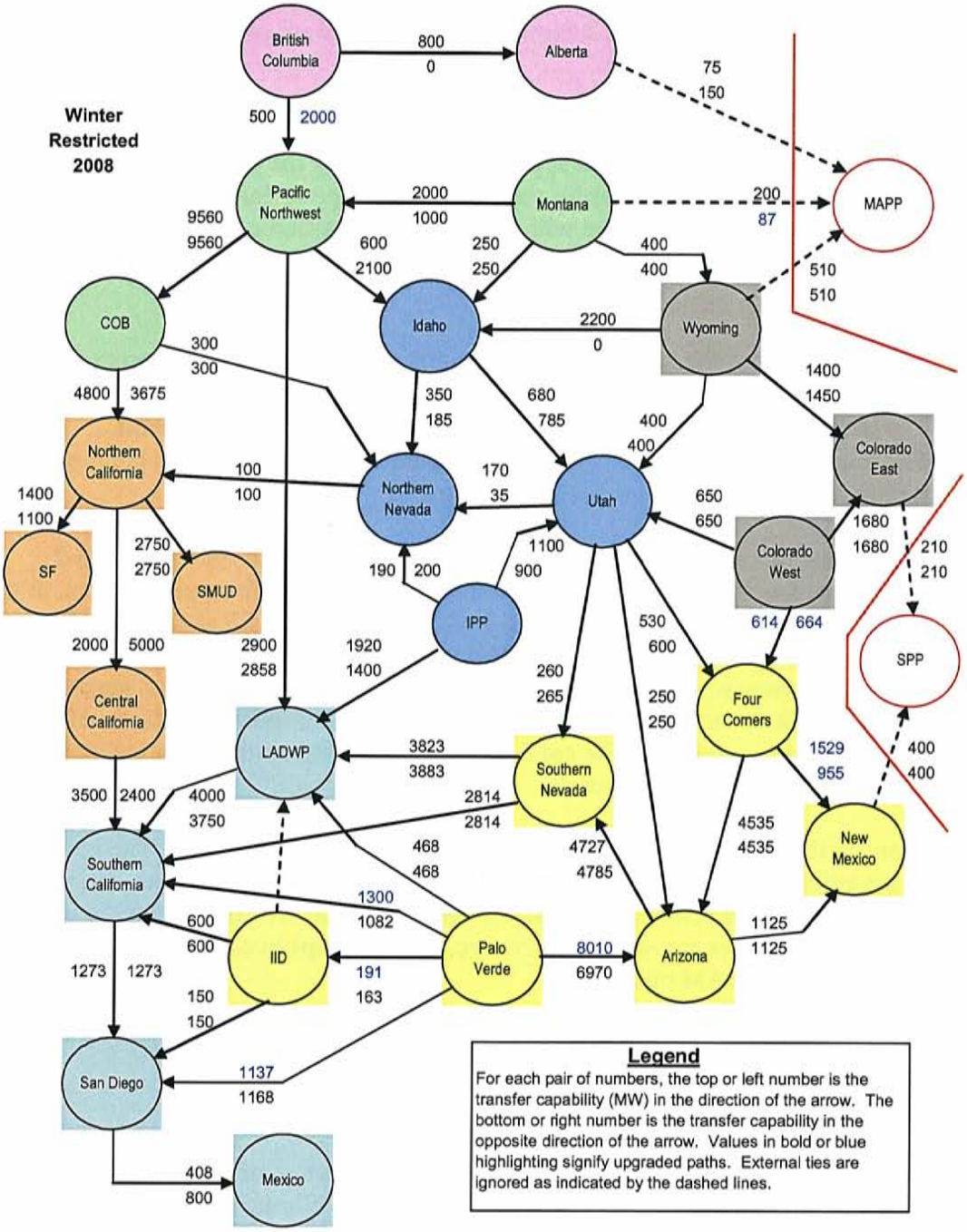
The assessment model is designed to measure the supply/demand margins based on forecasts of peak demands and resources. Peak demand forecasts for several years into the future are requested from the WECC control areas, as are the forecasts of resource additions. Due to the uncertainty of future resource additions, the validity of the results decreases the further out one looks. The assessment results for the period beyond 2013 are not a realistic picture of future supply margins. The addition of generation plants that are not accounted for in the current data should be expected, as well as some attrition of projects that are included in Class 2. There is a point where the results shift from a determination of supply margin to a determination of future needs.



Bubble Diagram #1 – Zone Topology (Summer – Restricted)



Bubble Diagram #2 – Zone Topology (Winter – Restricted)



# Attachment 2: Study Outline

## A. Study Details

The descriptions of the studies and a summary of the results were provided earlier in the Overview section.

Methodology

The assessment utilized a deterministic approach in evaluating the power supply margin[9] in meeting the total peak demand (firm plus non-firm) requirements for the peak hour of the study month. Uncertainties associated with such factors as resource availability and seasonal demand variations were considered explicitly by running additional cases. The primary input variations were:

- The adjustment to the load requirement to model the building block reserve margins and the severe temperature conditions, by escalating the peak demand forecast.
- The inclusion or exclusion of Class 2 resource additions and retirements.
- The treatment of resource outages such as scheduled maintenance, generation de-ratings, contingency outages and forced outages.

The peak demands represent the control area expected peak demand forecasts (1-in-2 probability, defined as 50% probability of not being exceeded) for the study months. It was assumed that the forecast monthly non-coincidental peak demands for each zone will occur at the same time (no diversity). In Case 5, the peak demand escalation was applied directly to the peak demand forecasts. For example, if the peak demand escalation for a summer case was 15%, the July peak demand forecast for each year was multiplied by a factor of 1.15. Peak demand escalation should not be confused with the load growth escalation that is already represented in the peak demand forecasts.

An equation for the power supply margin calculation is represented below. The internal resources are adjusted to account for scheduled maintenance, inoperable units, forced outages and hydro deratings. The demand is adjusted as previously described. The combination of all of the adjustments may seem overly conservative, but this helps to compensate for the optimistic nature of the SAM model.

Power Supply Margin = Zone Resources (adjusted) + Imports – Demand (adjusted) - Exports

Notable Changes since previous assessment

A new Basin sub-region was added to model the southern portion of the Northwest Power Pool. Idaho, Northern Nevada, and Utah are included in the Northwest Power Pool but they are located south of the North – South transmission constraint. The Basin sub-region was created to get an improved representation of the North – South constraint between these regions.

The determination of which planned resource changes to include was modified to change the completion time frames applied to Cases 1 - 5. Planned resource changes for these cases must

[9] Power Supply margin is the amount of resource capability (including imports) in excess of the demand requirements, after the specified adjustments to both demand and resources are applied.

be either under active construction and projected to be in-service by January 2011 for Class 1 resources, or under active regulatory review with an expected in-service date before January 2013 for Class 2 resources.

Qualifications

The assessment model is designed to measure the power supply margin based on forecasts of peak demands and seasonal resource capacity. While peak demand forecasts for several years into the future are readily available from the WECC control areas, the forecasts of resource additions are only accurate for a few years into the future. There is a point where the results shift from a determination of supply margin to a determination of future needs.

There is an ongoing concern regarding the potential retirement of several older generation plants, largely in California. Based on a traditional service life, numerous plants will be retiring over the time frame of this study. However, only the portion of these potential retirements that have been officially scheduled and reported to WECC are retired in the data used for this assessment. As more retirements are announced and reported, they will be represented in future assessments.

There is an important distinction between capacity and energy that must be considered, particularly for the Northwest sub-region. While a peak capacity study — such as is reported here — may show surplus capacity in the Northwest sub-region, the same level of capacity will not be available for a multi-hour period due to the limited availability of water under adverse water conditions. Eventually WECC hopes to develop a methodology for preparing an energy assessment that would help to evaluate the impact of adverse water conditions on available capacity.

A determination that a zone has sufficient resources and imports to meet its load requirement does not necessarily mean that all of the demand centers within that zone can meet their load requirements. Transmission constraints internal to a zone may limit capacity transfers to local demand areas, leaving them without a positive margin. These transmission-constrained local demand areas may include one or more major metropolitan areas within a zone and may include most of the total population within a zone. WECC's seasonal assessments and Ten-Year Coordinated Plan Summaries address potential intra-zonal resource inadequacies based on information provided by representatives from the various areas.

Status of Recommended Enhancements from Previous PSA Reports

- Consistent 1-in-2 peak demand forecasts – control areas representing over 96% of the total demand have verified that they reported a 1-in-2 peak demand forecast.
- Temperature based peak case – seasonal severe temperature-based cases are modeled in Cases 6 - 11.
- Probabilistic studies –The LRS has not determined a timeframe for adding probabilistic studies to the annual assessment.
- Energy assessment – The LRS postponed the question of an energy assessment while developing the building blocks for the planning reserve margin designed to evaluate summer peak demand conditions. It is the subject of future work.

## B. Input Data and Parameters

The specific input data used in the assessment are presented in Tables 14 – 22, beginning on page 56. The tables list the base generation resources and show the derivation of the power supply margin for each case.

**Demands**

Estimated monthly peak demands (firm and non-firm) for each SAM zone are included in the input data. These peak demands are derived from the peak demand forecasts that were submitted with the L&R data and represent a 1-in-2 year probability forecast (50% probability of not being exceeded). The non-firm demands include interruptible and load management demands as reported with the L&R data. This assessment includes the non-firm demands for all cases.

Where control areas spanned more than one zone, the demands were allocated by percentages (see details in Assumptions). The peak demands are aggregated by sub-region as presented in the summary tables in the results section.

Temperature Sensitivity

There is an expectation that the peak demand is directly correlated with the temperature(s) at the load centers. The applicable WECC members were requested to provide an indication of the approximate sensitivity (megawatts per degree Fahrenheit) of their peak demand to temperature variations. This data was used in this assessment to conduct severe temperature cases for both summer and winter.

**Resources**

The resource data include the existing generation units, the generation additions, the generation retirements, the scheduled maintenance, the inoperable generation, the forced outages and miscellaneous deratings. As the diversity of generating technologies has increased, WECC has not developed standardized methods for determining resource capacity values for balancing authorities to use when submitting the L&R data. Each is left to devise and implement a method of its own choosing. The net resource capacities submitted through the L&R process were summarized by zone and type (hydro or non-hydro) before being copied into the model. The detailed generation data are available in the WECC publication (*Existing Generation and Significant Additions and Changes to System Facilities 2007 – 2016*).

The summary tables in the results section provide details by sub-region for the generation capacities. Although the plans could change, generation retirements were considered by retirement date.

Scheduled maintenance and inoperable generation as reported in the L&R data were included as indicated in the studies. The majority of the July outages are scheduled for generation in Alberta and British Columbia. Other areas try to have all their units available for the summer peak. The generation owners in the summer peaking zones usually schedule their maintenance in the fall or spring.

**Resource Adjustments - Hydro**

In addition to the individual hydro generation capacities (seasonal median output) submitted with the L&R data, aggregate hydro capacities to reflect adverse water conditions are provided by the WECC control areas. The differences in total capacity represent the adverse hydro capacity de-rates for each control area.

The hydro generation unit capabilities submitted by the CAISO were generally nameplate capabilities. These were reduced to nominal levels in accordance with data provided by the CAISO.

The Northwest hydro was derated by approximately 1,800 MW in winter and 3,000 MW in summer, as submitted by the control area respondents. This duration does not adequately capture the limitations on the ability of the Northwest hydro system to meet multi-hour peak loads, particularly for export.

The hydro generation unit capabilities submitted by the BC Hydro and Power Authority are mostly 3-hour dependable capacity in the peak load period of weekday during the continuous two weeks of cold weather (in winter). Therefore, no de-rate was applied.

**Resource Adjustments – Non-hydro**

The non-hydro generation includes thermal steam generation, carbon fuel combustion generation, geothermal generation, solar generation, wind generation, and others. The non-hydro generation capacities were de-rated as specified for selected cases.

Wind De-rates

The current L&R data request does not specify the method that balancing authorities are to use when derating wind generation. The average derate is approximately 92%, leaving a capacity value of approximately 8%. The LRS examined a case with a capacity value of 0%. The result, due to the low initial values and the limited saturation of wind machines in the existing base and in Classes 1 and 2, was not significantly different from the original cases. In the future, as more wind capacity is installed and as better information on the net effect of large, dispersed wind farms becomes available, this analysis will be improved.

**Transfer Paths**

The transfer paths used by the program are based on the SAM zones, with paths connecting one SAM zone to another SAM zone where applicable. The model has data fields for the path, transfer capability, wheeling cost and loss factor. The wheeling costs for each path are used to calculate the transfer costs for any imports into a zone. The wheeling costs that were used were between $0 and $6.48. The loss factors are used to calculate the net transfer after losses for any imports into a zone. The loss factors were between 0% and 8%. Note that neither the wheeling cost nor the loss factors impeded the ability to import surplus resources to meet load.

The WECC control areas were requested to provide the appropriate values to use for the restricted transfer capabilities between zones.

## C. Results

The following attachments present additional results for the various cases, including tabular listings of the derivation of the annual power supply margins by WECC sub-region. Note that the extent of the supply surplus or deficiency for a given sub-region is subject to the inherent problems associated with the simplistic methodology. If multiple zones are in need of additional capacity, several factors may determine which zone(s) get access to any surplus capacity. Generally, the model will make excess capacity available first to the deficit zone that is closest to the surplus zone.

The results in this report are a measure of the amount of unused generation capacity (power supply margin) in each of the defined sub-regions under the specified conditions. The input data for the individual zones included reported generation and demand values, but excluded the reported firm contracts with entities in other zones. The model calculates the transfers between the zones based on the solution criteria and the provided transfer capabilities. A negative power supply margin for a zone or sub-region indicates resource shortages and/or transmission constraints. It is important to note that when the supply margin for a sub-region is zero (0), the sub-region is in resource/demand balance and it may be importing to meet its demand. At the point where the supply margin becomes negative, transmission constraints are preventing the sub-region from importing additional capacity.

## D. Reserve Margin

Reserve margin is a measure of the resource capability in excess of demand requirement. The industry commonly refers to two kinds of reserve margin, namely, operating reserve margin for day to day operations, and planning reserve margin for short or long term planning purposes. A planning reserve margin is generally higher than an operating reserve margin since it must account for all of the uncertainties. A planning reserve margin includes the margin for an operating reserve margin plus an additional margin for planning purposes.

The Minimum Operating Reliability Criteria Work Group (MORCWG) of WECC has defined an operating reserve requirement (operating reserve margin or contingency reserve) that requires a control area to maintain sufficient operating reserve as quoted below from the WECC Standard BAL-STD-002-0 – Operating Reserves.

"a. Minimum Operating Reserve. Each Balancing Authority shall maintain minimum Operating Reserve which is the sum of the following:

(i) Regulating reserve. Sufficient Spinning Reserve, immediately responsive to Automatic Generation Control (AGC) to provide sufficient regulating margin to allow the Balancing Authority to meet NERC's Control Performance Criteria (see BAL-001-0).

(ii) Contingency reserve. An amount of Spinning Reserve and Non-spinning Reserve (at least half of which must be Spinning Reserve), sufficient to meet the NERC Disturbance Control Standard BAL-002-0, equal to the greater of:

(a) The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single

contingency; or

(b) The sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation.

The combined unit ramp rate of each Balancing Authority's on-line, unloaded generating capacity must be capable of responding to the Spinning Reserve requirement of that Balancing Authority within ten minutes.

(iii) Additional reserve for interruptible imports. An amount of reserve, which can be made effective within ten minutes, equal to interruptible imports.

(iv) Additional reserve for on-demand obligations. An amount of reserve, which can be made effective within ten minutes, equal to on-demand obligations to other entities or Balancing Authorities."

WECC does not currently have a planning reserve margin requirement. However, the Power Supply Assessment Policy (see Attachment 3) defines a requirement to "project whether enough physical resources exist, at any price, to meet load and possible reserves while considering the transmission transfer capabilities of major paths." The Building Blocks reserve margin approach developed by LRS and approved by PCC and the WECC Board of Directors is a means to meet that requirement.

# APPENDIX A-5-K

Table 14 - Sub-region Resources - Class 1 Parameters (Summer)

| Parameter | Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| Existing Generation (in-service on 12/31/06) | Canada | 24,677 | 24,677 | 24,677 | 24,677 | 24,677 | 24,677 | 24,677 | 24,677 | 24,677 |
| | Northwest | 45,187 | 45,187 | 45,187 | 45,187 | 45,187 | 45,187 | 45,187 | 45,187 | 45,187 |
| | Basin | 11,384 | 11,384 | 11,384 | 11,384 | 11,384 | 11,384 | 11,384 | 11,384 | 11,384 |
| | Rockies | 16,293 | 16,293 | 16,293 | 16,293 | 16,293 | 16,293 | 16,293 | 16,293 | 16,293 |
| | Desert SW | 39,013 | 39,013 | 39,013 | 39,013 | 39,013 | 39,013 | 39,013 | 39,013 | 39,013 |
| | No. CA | 30,496 | 30,496 | 30,496 | 30,496 | 30,496 | 30,496 | 30,496 | 30,496 | 30,496 |
| | So. CA/MX | 29,782 | 29,782 | 29,782 | 29,782 | 29,782 | 29,782 | 29,782 | 29,782 | 29,782 |
| | Total | 196,832 | 196,832 | 196,832 | 196,832 | 196,832 | 196,832 | 196,832 | 196,832 | 196,832 |
| Existing Hydro Generation | Canada | 12,549 | 12,549 | 12,549 | 12,549 | 12,549 | 12,549 | 12,549 | 12,549 | 12,549 |
| | Northwest | 33,036 | 33,036 | 33,036 | 33,036 | 33,036 | 33,036 | 33,036 | 33,036 | 33,036 |
| | Basin | 2,555 | 2,555 | 2,555 | 2,555 | 2,555 | 2,555 | 2,555 | 2,555 | 2,555 |
| | Rockies | 1,790 | 1,790 | 1,790 | 1,790 | 1,790 | 1,790 | 1,790 | 1,790 | 1,790 |
| | Desert SW | 3,581 | 3,581 | 3,581 | 3,581 | 3,581 | 3,581 | 3,581 | 3,581 | 3,581 |
| | No. CA | 9,951 | 9,951 | 9,951 | 9,951 | 9,951 | 9,951 | 9,951 | 9,951 | 9,951 |
| | So. CA/MX | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 |
| | Total | 66,659 | 66,659 | 66,659 | 66,659 | 66,659 | 66,659 | 66,659 | 66,659 | 66,659 |
| Existing NonHydro Generation | Canada | 12,128 | 12,128 | 12,128 | 12,128 | 12,128 | 12,128 | 12,128 | 12,128 | 12,128 |
| | Northwest | 12,151 | 12,151 | 12,151 | 12,151 | 12,151 | 12,151 | 12,151 | 12,151 | 12,151 |
| | Basin | 8,830 | 8,830 | 8,830 | 8,830 | 8,830 | 8,830 | 8,830 | 8,830 | 8,830 |
| | Rockies | 14,503 | 14,503 | 14,503 | 14,503 | 14,503 | 14,503 | 14,503 | 14,503 | 14,503 |
| | Desert SW | 35,432 | 35,432 | 35,432 | 35,432 | 35,432 | 35,432 | 35,432 | 35,432 | 35,432 |
| | No. CA | 20,544 | 20,544 | 20,544 | 20,544 | 20,544 | 20,544 | 20,544 | 20,544 | 20,544 |
| | So. CA/MX | 26,584 | 26,584 | 26,584 | 26,584 | 26,584 | 26,584 | 26,584 | 26,584 | 26,584 |
| | Total | 130,172 | 130,172 | 130,172 | 130,172 | 130,172 | 130,172 | 130,172 | 130,172 | 130,172 |
| Net Class 1 Additions/Retirements (cutoff is study month) | Canada | 316 | 20 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Northwest | 1,456 | -2 | 12 | 12 | 12 | 0 | 0 | 0 | 0 |
| | Basin | 1,294 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Rockies | 469 | 0 | 750 | 274 | 0 | 0 | 0 | 0 | 0 |
| | Desert SW | 592 | 208 | 400 | 0 | 0 | 0 | 0 | 0 | 0 |
| | No. CA | 377 | -5 | 530 | 0 | 0 | 0 | 0 | 0 | 0 |
| | So. CA/MX | 1,324 | 494 | 93 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total | 5,827 | 715 | 1,785 | 286 | 12 | 0 | 0 | 0 | 0 |
| Cumulative Committed Additions/Retirements | Canada | 316 | 336 | 336 | 336 | 336 | 336 | 336 | 336 | 336 |
| | Northwest | 1,456 | 1,454 | 1,466 | 1,478 | 1,491 | 1,491 | 1,491 | 1,491 | 1,491 |
| | Basin | 1,294 | 1,294 | 1,294 | 1,294 | 1,294 | 1,294 | 1,294 | 1,294 | 1,294 |
| | Rockies | 469 | 469 | 1,219 | 1,493 | 1,493 | 1,493 | 1,493 | 1,493 | 1,493 |
| | Desert SW | 592 | 800 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 |
| | No. CA | 377 | 372 | 902 | 902 | 902 | 902 | 902 | 902 | 902 |
| | So. CA/MX | 1,324 | 1,818 | 1,911 | 1,911 | 1,911 | 1,911 | 1,911 | 1,911 | 1,911 |
| | Total | 5,827 | 6,543 | 8,328 | 8,614 | 8,627 | 8,627 | 8,627 | 8,627 | 8,627 |
| Hydro Derates | Canada | -26 | -29 | -26 | -26 | -26 | -26 | -26 | -26 | -26 |
| | Northwest | -3,034 | -3,032 | -2,952 | -2,951 | -2,951 | -2,951 | -2,951 | -2,951 | -2,951 |
| | Basin | -447 | -447 | -447 | -447 | -447 | -447 | -447 | -447 | -447 |
| | Rockies | -10 | -10 | -10 | -10 | -10 | -10 | -10 | -10 | -10 |
| | Desert SW | -57 | -57 | -57 | -57 | -57 | -57 | -57 | -57 | -57 |
| | No. CA | -497 | -497 | -497 | -497 | -497 | -497 | -497 | -497 | -497 |
| | So. CA/MX | -216 | -216 | -216 | -216 | -216 | -216 | -216 | -216 | -216 |
| | Total | -4,287 | -4,288 | -4,205 | -4,204 | -4,204 | -4,204 | -4,204 | -4,204 | -4,204 |
| Other Fixed Adjustments | Canada | | | | | | | | | |
| | Northwest | | | | | | | | | |
| | Basin | | | | | | | | | |
| | Rockies | | | | | | | | | |
| | Desert SW | 325 | 325 | 325 | 325 | 325 | 325 | 325 | 325 | 325 |
| | No. CA | | | | | | | | | |
| | So. CA/MX | | | | | | | | | |
| | Total | 325 | 325 | 325 | 325 | 325 | 325 | 325 | 325 | 325 |
| Net Base Resource Capacity | Canada | 24,967 | 24,984 | 24,987 | 24,987 | 24,987 | 24,987 | 24,987 | 24,987 | 24,987 |
| | Northwest | 43,609 | 43,609 | 43,701 | 43,714 | 43,727 | 43,727 | 43,727 | 43,727 | 43,727 |
| | Basin | 12,231 | 12,231 | 12,231 | 12,231 | 12,231 | 12,231 | 12,231 | 12,231 | 12,231 |
| | Rockies | 16,752 | 16,752 | 17,502 | 17,776 | 17,776 | 17,776 | 17,776 | 17,776 | 17,776 |
| | Desert SW | 39,873 | 40,081 | 40,481 | 40,481 | 40,481 | 40,481 | 40,481 | 40,481 | 40,481 |
| | No. CA | 30,376 | 30,371 | 30,901 | 30,901 | 30,901 | 30,901 | 30,901 | 30,901 | 30,901 |
| | So. CA/MX | 30,890 | 31,384 | 31,477 | 31,477 | 31,477 | 31,477 | 31,477 | 31,477 | 31,477 |
| | Total | 198,697 | 199,412 | 201,280 | 201,567 | 201,580 | 201,580 | 201,580 | 201,580 | 201,580 |

Table 15 - Sub-region Resources - Class 1 & 2 Parameters (Summer)

| Parameter | Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| Existing Generation (in-service on 12/31/06) | Canada | 24,677 | 24,677 | 24,677 | 24,677 | 24,677 | 24,677 | 24,677 | 24,677 | 24,677 |
| | Northwest | 45,187 | 45,187 | 45,187 | 45,187 | 45,187 | 45,187 | 45,187 | 45,187 | 45,187 |
| | Basin | 11,384 | 11,384 | 11,384 | 11,384 | 11,384 | 11,384 | 11,384 | 11,384 | 11,384 |
| | Rockies | 16,293 | 16,293 | 16,293 | 16,293 | 16,293 | 16,293 | 16,293 | 16,293 | 16,293 |
| | Desert SW | 39,013 | 39,013 | 39,013 | 39,013 | 39,013 | 39,013 | 39,013 | 39,013 | 39,013 |
| | No. CA | 30,496 | 30,496 | 30,496 | 30,496 | 30,496 | 30,496 | 30,496 | 30,496 | 30,496 |
| | So. CA/MX | 29,782 | 29,782 | 29,782 | 29,782 | 29,782 | 29,782 | 29,782 | 29,782 | 29,782 |
| | Total | 196,832 | 196,832 | 196,832 | 196,832 | 196,832 | 196,832 | 196,832 | 196,832 | 196,832 |
| Existing Hydro Generation | Canada | 12,549 | 12,549 | 12,549 | 12,549 | 12,549 | 12,549 | 12,549 | 12,549 | 12,549 |
| | Northwest | 33,036 | 33,036 | 33,036 | 33,036 | 33,036 | 33,036 | 33,036 | 33,036 | 33,036 |
| | Basin | 2,555 | 2,555 | 2,555 | 2,555 | 2,555 | 2,555 | 2,555 | 2,555 | 2,555 |
| | Rockies | 1,790 | 1,790 | 1,790 | 1,790 | 1,790 | 1,790 | 1,790 | 1,790 | 1,790 |
| | Desert SW | 3,581 | 3,581 | 3,581 | 3,581 | 3,581 | 3,581 | 3,581 | 3,581 | 3,581 |
| | No. CA | 9,951 | 9,951 | 9,951 | 9,951 | 9,951 | 9,951 | 9,951 | 9,951 | 9,951 |
| | So. CA/MX | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 |
| | Total | 66,659 | 66,659 | 66,659 | 66,659 | 66,659 | 66,659 | 66,659 | 66,659 | 66,659 |
| Existing NonHydro Generation | Canada | 12,128 | 12,128 | 12,128 | 12,128 | 12,128 | 12,128 | 12,128 | 12,128 | 12,128 |
| | Northwest | 12,151 | 12,151 | 12,151 | 12,151 | 12,151 | 12,151 | 12,151 | 12,151 | 12,151 |
| | Basin | 8,830 | 8,830 | 8,830 | 8,830 | 8,830 | 8,830 | 8,830 | 8,830 | 8,830 |
| | Rockies | 14,503 | 14,503 | 14,503 | 14,503 | 14,503 | 14,503 | 14,503 | 14,503 | 14,503 |
| | Desert SW | 35,432 | 35,432 | 35,432 | 35,432 | 35,432 | 35,432 | 35,432 | 35,432 | 35,432 |
| | No. CA | 20,544 | 20,544 | 20,544 | 20,544 | 20,544 | 20,544 | 20,544 | 20,544 | 20,544 |
| | So. CA/MX | 26,584 | 26,584 | 26,584 | 26,584 | 26,584 | 26,584 | 26,584 | 26,584 | 26,584 |
| | Total | 130,172 | 130,172 | 130,172 | 130,172 | 130,172 | 130,172 | 130,172 | 130,172 | 130,172 |
| Net Class 1 & Class 2 Additions/Retirements (cutoff is study month) | Canada | 316 | 135 | 60 | 950 | 0 | 0 | 0 | 0 | 0 |
| | Northwest | 1,523 | 28 | 12 | 12 | 12 | 0 | 0 | 0 | 0 |
| | Basin | 1,459 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Rockies | 596 | 0 | 750 | 274 | 0 | 0 | 0 | 0 | 0 |
| | Desert SW | 592 | 208 | 400 | 0 | 0 | 0 | 0 | 0 | 0 |
| | No. CA | 984 | 1,230 | 648 | 0 | 0 | 0 | 0 | 0 | 0 |
| | So. CA/MX | 1,324 | 1,065 | 1,568 | 610 | 0 | 0 | 0 | 0 | 0 |
| | Total | 6,794 | 2,666 | 3,438 | 1,846 | 12 | 0 | 0 | 0 | 0 |
| Cumulative Committed Additions/Retirements | Canada | 316 | 451 | 511 | 1,461 | 1,461 | 1,461 | 1,461 | 1,461 | 1,461 |
| | Northwest | 1,523 | 1,551 | 1,563 | 1,575 | 1,588 | 1,588 | 1,588 | 1,588 | 1,588 |
| | Basin | 1,459 | 1,459 | 1,459 | 1,459 | 1,459 | 1,459 | 1,459 | 1,459 | 1,459 |
| | Rockies | 596 | 596 | 1,346 | 1,620 | 1,620 | 1,620 | 1,620 | 1,620 | 1,620 |
| | Desert SW | 592 | 800 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 |
| | No. CA | 984 | 2,214 | 2,862 | 2,862 | 2,862 | 2,862 | 2,862 | 2,862 | 2,862 |
| | So. CA/MX | 1,324 | 2,389 | 3,957 | 4,567 | 4,567 | 4,567 | 4,567 | 4,567 | 4,567 |
| | Total | 6,794 | 9,460 | 12,898 | 14,745 | 14,757 | 14,757 | 14,757 | 14,757 | 14,757 |
| Hydro Derates | Canada | -26 | -29 | -26 | -26 | -26 | -26 | -26 | -26 | -26 |
| | Northwest | -3,034 | -3,032 | -2,952 | -2,951 | -2,951 | -2,951 | -2,951 | -2,951 | -2,951 |
| | Basin | -447 | -447 | -447 | -447 | -447 | -447 | -447 | -447 | -447 |
| | Rockies | -10 | -10 | -10 | -10 | -10 | -10 | -10 | -10 | -10 |
| | Desert SW | -57 | -57 | -57 | -57 | -57 | -57 | -57 | -57 | -57 |
| | No. CA | -497 | -497 | -497 | -497 | -497 | -497 | -497 | -497 | -497 |
| | So. CA/MX | -216 | -216 | -216 | -216 | -216 | -216 | -216 | -216 | -216 |
| | Total | -4,287 | -4,288 | -4,205 | -4,204 | -4,204 | -4,204 | -4,204 | -4,204 | -4,204 |
| Other Fixed Adjustments | Canada | | | | | | | | | |
| | Northwest | | | | | | | | | |
| | Basin | | | | | | | | | |
| | Rockies | | | | | | | | | |
| | Desert SW | 325 | 325 | 325 | 325 | 325 | 325 | 325 | 325 | 325 |
| | No. CA | | | | | | | | | |
| | So. CA/MX | | | | | | | | | |
| | Total | 325 | 325 | 325 | 325 | 325 | 325 | 325 | 325 | 325 |
| Net Base Resource Capacity | Canada | 24,967 | 25,099 | 25,162 | 26,112 | 26,112 | 26,112 | 26,112 | 26,112 | 26,112 |
| | Northwest | 43,676 | 43,706 | 43,798 | 43,811 | 43,824 | 43,824 | 43,824 | 43,824 | 43,824 |
| | Basin | 12,396 | 12,396 | 12,396 | 12,396 | 12,396 | 12,396 | 12,396 | 12,396 | 12,396 |
| | Rockies | 16,879 | 16,879 | 17,629 | 17,903 | 17,903 | 17,903 | 17,903 | 17,903 | 17,903 |
| | Desert SW | 39,873 | 40,081 | 40,481 | 40,481 | 40,481 | 40,481 | 40,481 | 40,481 | 40,481 |
| | No. CA | 30,983 | 32,213 | 32,861 | 32,861 | 32,861 | 32,861 | 32,861 | 32,861 | 32,861 |
| | So. CA/MX | 30,890 | 31,955 | 33,523 | 34,133 | 34,133 | 34,133 | 34,133 | 34,133 | 34,133 |
| | Total | 199,664 | 202,329 | 205,850 | 207,698 | 207,710 | 207,710 | 207,710 | 207,710 | 207,710 |

Table 16 - Sub-region Resources - Class 1 Parameters (Winter)

| Parameter | Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| Existing Generation (in-service on 12/31/05) | Canada | 23,945 | 23,945 | 23,945 | 23,945 | 23,945 | 23,945 | 23,945 | 23,945 | 23,945 |
| | Northwest | 44,889 | 44,889 | 44,889 | 44,889 | 44,889 | 44,889 | 44,889 | 44,889 | 44,889 |
| | Basin | 11,116 | 11,116 | 11,116 | 11,116 | 11,116 | 11,116 | 11,116 | 11,116 | 11,116 |
| | Rockies | 16,689 | 16,689 | 16,689 | 16,689 | 16,689 | 16,689 | 16,689 | 16,689 | 16,689 |
| | Desert SW | 40,115 | 40,115 | 40,115 | 40,115 | 40,115 | 40,115 | 40,115 | 40,115 | 40,115 |
| | No. CA | 30,561 | 30,561 | 30,561 | 30,561 | 30,561 | 30,561 | 30,561 | 30,561 | 30,561 |
| | So. CA/MX | 29,760 | 29,760 | 29,760 | 29,760 | 29,760 | 29,760 | 29,760 | 29,760 | 29,760 |
| | Total | 197,075 | 197,075 | 197,075 | 197,075 | 197,075 | 197,075 | 197,075 | 197,075 | 197,075 |
| Existing Hydro Generation | Canada | 11,779 | 11,779 | 11,779 | 11,779 | 11,779 | 11,779 | 11,779 | 11,779 | 11,779 |
| | Northwest | 32,529 | 32,529 | 32,529 | 32,529 | 32,529 | 32,529 | 32,529 | 32,529 | 32,529 |
| | Basin | 2,149 | 2,149 | 2,149 | 2,149 | 2,149 | 2,149 | 2,149 | 2,149 | 2,149 |
| | Rockies | 1,746 | 1,746 | 1,746 | 1,746 | 1,746 | 1,746 | 1,746 | 1,746 | 1,746 |
| | Desert SW | 3,512 | 3,512 | 3,512 | 3,512 | 3,512 | 3,512 | 3,512 | 3,512 | 3,512 |
| | No. CA | 9,956 | 9,956 | 9,956 | 9,956 | 9,956 | 9,956 | 9,956 | 9,956 | 9,956 |
| | So. CA/MX | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 |
| | Total | 64,868 | 64,868 | 64,868 | 64,868 | 64,868 | 64,868 | 64,868 | 64,868 | 64,868 |
| Existing NonHydro Generation | Canada | 12,166 | 12,166 | 12,166 | 12,166 | 12,166 | 12,166 | 12,166 | 12,166 | 12,166 |
| | Northwest | 12,361 | 12,361 | 12,361 | 12,361 | 12,361 | 12,361 | 12,361 | 12,361 | 12,361 |
| | Basin | 8,968 | 8,968 | 8,968 | 8,968 | 8,968 | 8,968 | 8,968 | 8,968 | 8,968 |
| | Rockies | 14,942 | 14,942 | 14,942 | 14,942 | 14,942 | 14,942 | 14,942 | 14,942 | 14,942 |
| | Desert SW | 36,602 | 36,602 | 36,602 | 36,602 | 36,602 | 36,602 | 36,602 | 36,602 | 36,602 |
| | No. CA | 20,605 | 20,605 | 20,605 | 20,605 | 20,605 | 20,605 | 20,605 | 20,605 | 20,605 |
| | So. CA/MX | 26,563 | 26,563 | 26,563 | 26,563 | 26,563 | 26,563 | 26,563 | 26,563 | 26,563 |
| | Total | 132,207 | 132,207 | 132,207 | 132,207 | 132,207 | 132,207 | 132,207 | 132,207 | 132,207 |
| Net Class 1 Additions/Retirements (cutoff is study month) | Canada | 317 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Northwest | 1,510 | 12 | 12 | 12 | 12 | 0 | 0 | 0 | 0 |
| | Basin | 1,299 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Rockies | 513 | 0 | 1,062 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Desert SW | 592 | 608 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | No. CA | 372 | 480 | 50 | 0 | 0 | 0 | 0 | 0 | 0 |
| | So. CA/MX | 1,324 | 494 | 93 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total | 5,927 | 1,594 | 1,217 | 12 | 12 | 0 | 0 | 0 | 0 |
| Cumulative Committed Additions/Retirements | Canada | 317 | 317 | 317 | 317 | 317 | 317 | 317 | 317 | 317 |
| | Northwest | 1,510 | 1,522 | 1,535 | 1,547 | 1,560 | 1,560 | 1,560 | 1,560 | 1,560 |
| | Basin | 1,299 | 1,299 | 1,299 | 1,299 | 1,299 | 1,299 | 1,299 | 1,299 | 1,299 |
| | Rockies | 513 | 513 | 1,575 | 1,575 | 1,575 | 1,575 | 1,575 | 1,575 | 1,575 |
| | Desert SW | 592 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 |
| | No. CA | 372 | 852 | 902 | 902 | 902 | 902 | 902 | 902 | 902 |
| | So. CA/MX | 1,324 | 1,818 | 1,911 | 1,911 | 1,911 | 1,911 | 1,911 | 1,911 | 1,911 |
| | Total | 5,927 | 7,521 | 8,739 | 8,751 | 8,763 | 8,763 | 8,763 | 8,763 | 8,763 |
| Hydro Derates | Canada | -163 | -163 | -163 | -163 | -163 | -163 | -163 | -163 | -163 |
| | Northwest | -1,847 | -1,845 | -1,845 | -1,844 | -1,844 | -1,844 | -1,844 | -1,844 | -1,844 |
| | Basin | -440 | -440 | -440 | -440 | -440 | -440 | -440 | -440 | -440 |
| | Rockies | -64 | -64 | -64 | -64 | -64 | -64 | -64 | -64 | -64 |
| | Desert SW | -69 | -69 | -69 | -69 | -69 | -69 | -69 | -69 | -69 |
| | No. CA | -506 | -506 | -506 | -506 | -506 | -506 | -506 | -506 | -506 |
| | So. CA/MX | -217 | -217 | -217 | -217 | -217 | -217 | -217 | -217 | -217 |
| | Total | -3,306 | -3,304 | -3,304 | -3,303 | -3,303 | -3,303 | -3,303 | -3,303 | -3,303 |
| Other Fixed Adjustments | Canada | | | | | | | | | |
| | Northwest | | | | | | | | | |
| | Basin | | | | | | | | | |
| | Rockies | | | | | | | | | |
| | Desert SW | 325 | 325 | 325 | 325 | 325 | 325 | 325 | 325 | 325 |
| | No. CA | | | | | | | | | |
| | So. CA/MX | | | | | | | | | |
| | Total | 325 | 325 | 325 | 325 | 325 | 325 | 325 | 325 | 325 |
| Net Base Resource Capacity | Canada | 24,099 | 24,099 | 24,099 | 24,099 | 24,099 | 24,099 | 24,099 | 24,099 | 24,099 |
| | Northwest | 44,552 | 44,566 | 44,579 | 44,592 | 44,605 | 44,605 | 44,605 | 44,605 | 44,605 |
| | Basin | 11,975 | 11,975 | 11,975 | 11,975 | 11,975 | 11,975 | 11,975 | 11,975 | 11,975 |
| | Rockies | 17,138 | 17,138 | 18,200 | 18,200 | 18,200 | 18,200 | 18,200 | 18,200 | 18,200 |
| | Desert SW | 40,963 | 41,571 | 41,571 | 41,571 | 41,571 | 41,571 | 41,571 | 41,571 | 41,571 |
| | No. CA | 30,427 | 30,907 | 30,957 | 30,957 | 30,957 | 30,957 | 30,957 | 30,957 | 30,957 |
| | So. CA/MX | 30,867 | 31,361 | 31,454 | 31,454 | 31,454 | 31,454 | 31,454 | 31,454 | 31,454 |
| | Total | 200,021 | 201,617 | 202,835 | 202,848 | 202,860 | 202,860 | 202,860 | 202,860 | 202,860 |

Table 17 - Sub-region Resources - Class 1 & 2 Parameters (Winter)

| Parameter | Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| Existing Generation (in-service on 12/31/05) | Canada | 23,945 | 23,945 | 23,945 | 23,945 | 23,945 | 23,945 | 23,945 | 23,945 | 23,945 |
| | Northwest | 44,889 | 44,889 | 44,889 | 44,889 | 44,889 | 44,889 | 44,889 | 44,889 | 44,889 |
| | Basin | 11,116 | 11,116 | 11,116 | 11,116 | 11,116 | 11,116 | 11,116 | 11,116 | 11,116 |
| | Rockies | 16,689 | 16,689 | 16,689 | 16,689 | 16,689 | 16,689 | 16,689 | 16,689 | 16,689 |
| | Desert SW | 40,115 | 40,115 | 40,115 | 40,115 | 40,115 | 40,115 | 40,115 | 40,115 | 40,115 |
| | No. CA | 30,561 | 30,561 | 30,561 | 30,561 | 30,561 | 30,561 | 30,561 | 30,561 | 30,561 |
| | So. CA/MX | 29,760 | 29,760 | 29,760 | 29,760 | 29,760 | 29,760 | 29,760 | 29,760 | 29,760 |
| | Total | 197,075 | 197,075 | 197,075 | 197,075 | 197,075 | 197,075 | 197,075 | 197,075 | 197,075 |
| Existing Hydro Generation | Canada | 11,779 | 11,779 | 11,779 | 11,779 | 11,779 | 11,779 | 11,779 | 11,779 | 11,779 |
| | Northwest | 32,529 | 32,529 | 32,529 | 32,529 | 32,529 | 32,529 | 32,529 | 32,529 | 32,529 |
| | Basin | 2,149 | 2,149 | 2,149 | 2,149 | 2,149 | 2,149 | 2,149 | 2,149 | 2,149 |
| | Rockies | 1,746 | 1,746 | 1,746 | 1,746 | 1,746 | 1,746 | 1,746 | 1,746 | 1,746 |
| | Desert SW | 3,512 | 3,512 | 3,512 | 3,512 | 3,512 | 3,512 | 3,512 | 3,512 | 3,512 |
| | No. CA | 9,956 | 9,956 | 9,956 | 9,956 | 9,956 | 9,956 | 9,956 | 9,956 | 9,956 |
| | So. CA/MX | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 | 3,197 |
| | Total | 64,868 | 64,868 | 64,868 | 64,868 | 64,868 | 64,868 | 64,868 | 64,868 | 64,868 |
| Existing NonHydro Generation | Canada | 12,166 | 12,166 | 12,166 | 12,166 | 12,166 | 12,166 | 12,166 | 12,166 | 12,166 |
| | Northwest | 12,361 | 12,361 | 12,361 | 12,361 | 12,361 | 12,361 | 12,361 | 12,361 | 12,361 |
| | Basin | 8,968 | 8,968 | 8,968 | 8,968 | 8,968 | 8,968 | 8,968 | 8,968 | 8,968 |
| | Rockies | 14,942 | 14,942 | 14,942 | 14,942 | 14,942 | 14,942 | 14,942 | 14,942 | 14,942 |
| | Desert SW | 36,602 | 36,602 | 36,602 | 36,602 | 36,602 | 36,602 | 36,602 | 36,602 | 36,602 |
| | No. CA | 20,605 | 20,605 | 20,605 | 20,605 | 20,605 | 20,605 | 20,605 | 20,605 | 20,605 |
| | So. CA/MX | 26,563 | 26,563 | 26,563 | 26,563 | 26,563 | 26,563 | 26,563 | 26,563 | 26,563 |
| | Total | 132,207 | 132,207 | 132,207 | 132,207 | 132,207 | 132,207 | 132,207 | 132,207 | 132,207 |
| Net Class 1 & Class 2 Additions/Retirements (cutoff is study month) | Canada | 402 | 30 | 560 | 450 | 0 | 0 | 0 | 0 | 0 |
| | Northwest | 1,607 | 12 | 12 | 12 | 12 | 0 | 0 | 0 | 0 |
| | Basin | 1,477 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Rockies | 640 | 0 | 1,062 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Desert SW | 592 | 608 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | No. CA | 1,099 | 1,714 | 50 | 0 | 0 | 0 | 0 | 0 | 0 |
| | So. CA/MX | 1,324 | 2,540 | 703 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total | 7,140 | 4,904 | 2,387 | 462 | 12 | 0 | 0 | 0 | 0 |
| Cumulative Committed Additions/Retirements | Canada | 402 | 432 | 992 | 1,442 | 1,442 | 1,442 | 1,442 | 1,442 | 1,442 |
| | Northwest | 1,607 | 1,619 | 1,632 | 1,644 | 1,657 | 1,657 | 1,657 | 1,657 | 1,657 |
| | Basin | 1,477 | 1,477 | 1,477 | 1,477 | 1,477 | 1,477 | 1,477 | 1,477 | 1,477 |
| | Rockies | 640 | 640 | 1,702 | 1,702 | 1,702 | 1,702 | 1,702 | 1,702 | 1,702 |
| | Desert SW | 592 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 | 1,200 |
| | No. CA | 1,099 | 2,813 | 2,863 | 2,863 | 2,863 | 2,863 | 2,863 | 2,863 | 2,863 |
| | So. CA/MX | 1,324 | 3,864 | 4,567 | 4,567 | 4,567 | 4,567 | 4,567 | 4,567 | 4,567 |
| | Total | 7,140 | 12,045 | 14,432 | 14,894 | 14,907 | 14,907 | 14,907 | 14,907 | 14,907 |
| Hydro Derates | Canada | -163 | -163 | -163 | -163 | -163 | -163 | -163 | -163 | -163 |
| | Northwest | -1,847 | -1,845 | -1,845 | -1,844 | -1,844 | -1,844 | -1,844 | -1,844 | -1,844 |
| | Basin | -440 | -440 | -440 | -440 | -440 | -440 | -440 | -440 | -440 |
| | Rockies | -64 | -64 | -64 | -64 | -64 | -64 | -64 | -64 | -64 |
| | Desert SW | -69 | -69 | -69 | -69 | -69 | -69 | -69 | -69 | -69 |
| | No. CA | -506 | -506 | -506 | -506 | -506 | -506 | -506 | -506 | -506 |
| | So. CA/MX | -217 | -217 | -217 | -217 | -217 | -217 | -217 | -217 | -217 |
| | Total | -3,306 | -3,304 | -3,304 | -3,303 | -3,303 | -3,303 | -3,303 | -3,303 | -3,303 |
| Other Fixed Adjustments | Canada | | | | | | | | | |
| | Northwest | | | | | | | | | |
| | Basin | | | | | | | | | |
| | Rockies | | | | | | | | | |
| | Desert SW | 325 | 325 | 325 | 325 | 325 | 325 | 325 | 325 | 325 |
| | No. CA | | | | | | | | | |
| | So. CA/MX | | | | | | | | | |
| | Total | 325 | 325 | 325 | 325 | 325 | 325 | 325 | 325 | 325 |
| Net Base Resource Capacity | Canada | 24,184 | 24,214 | 24,774 | 25,224 | 25,224 | 25,224 | 25,224 | 25,224 | 25,224 |
| | Northwest | 44,649 | 44,663 | 44,676 | 44,689 | 44,702 | 44,702 | 44,702 | 44,702 | 44,702 |
| | Basin | 12,153 | 12,153 | 12,153 | 12,153 | 12,153 | 12,153 | 12,153 | 12,153 | 12,153 |
| | Rockies | 17,265 | 17,265 | 18,327 | 18,327 | 18,327 | 18,327 | 18,327 | 18,327 | 18,327 |
| | Desert SW | 40,963 | 41,571 | 41,571 | 41,571 | 41,571 | 41,571 | 41,571 | 41,571 | 41,571 |
| | No. CA | 31,154 | 32,868 | 32,918 | 32,918 | 32,918 | 32,918 | 32,918 | 32,918 | 32,918 |
| | So. CA/MX | 30,867 | 33,407 | 34,110 | 34,110 | 34,110 | 34,110 | 34,110 | 34,110 | 34,110 |
| | Total | 201,234 | 206,141 | 208,528 | 208,991 | 209,004 | 209,004 | 209,004 | 209,004 | 209,004 |

Table 18 - Sub-region Summary - Case #1

| Parameter | Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| Firm Demand | Canada | 17,568 | 17,955 | 18,319 | 18,659 | 18,972 | 19,367 | 19,709 | 19,993 | 20,422 |
| | Northwest | 23,922 | 24,183 | 24,505 | 24,804 | 25,074 | 25,397 | 25,723 | 26,064 | 26,487 |
| | Basin | 11,850 | 12,289 | 12,549 | 12,850 | 13,126 | 13,463 | 13,763 | 14,113 | 14,370 |
| | Rockies | 12,635 | 12,994 | 13,323 | 13,617 | 13,917 | 14,216 | 14,562 | 14,934 | 15,286 |
| | Desert SW | 30,573 | 31,543 | 32,531 | 33,464 | 34,331 | 35,261 | 36,162 | 37,095 | 37,978 |
| | No. CA | 26,148 | 26,595 | 27,074 | 27,547 | 28,025 | 28,509 | 28,975 | 29,461 | 29,970 |
| | So. CA/MX | 33,899 | 34,346 | 34,936 | 35,510 | 36,192 | 36,705 | 37,342 | 37,992 | 38,762 |
| | Total | 156,595 | 159,905 | 163,237 | 166,451 | 169,637 | 172,918 | 176,236 | 179,652 | 183,275 |
| Non-Firm Demand | Canada | 299 | 299 | 299 | 299 | 299 | 299 | 299 | 299 | 299 |
| | Northwest | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Basin | 211 | 211 | 211 | 211 | 211 | 211 | 211 | 211 | 211 |
| | Rockies | 265 | 281 | 296 | 310 | 321 | 330 | 327 | 317 | 308 |
| | Desert SW | 306 | 340 | 344 | 359 | 364 | 369 | 374 | 404 | 408 |
| | No. CA | 1,314 | 1,316 | 1,316 | 1,317 | 1,318 | 1,320 | 1,320 | 1,321 | 1,323 |
| | So. CA/MX | 1,384 | 1,411 | 1,438 | 1,489 | 1,534 | 1,571 | 1,607 | 1,637 | 1,663 |
| | Total | 3,779 | 3,858 | 3,904 | 3,985 | 4,047 | 4,100 | 4,138 | 4,189 | 4,212 |
| Building Block Reserve Requirement | Canada | 2,103 | 2,150 | 2,193 | 2,234 | 2,271 | 2,319 | 2,359 | 2,393 | 2,444 |
| | Northwest | 3,286 | 3,321 | 3,366 | 3,407 | 3,444 | 3,488 | 3,533 | 3,580 | 3,638 |
| | Basin | 1,519 | 1,575 | 1,608 | 1,646 | 1,681 | 1,725 | 1,764 | 1,808 | 1,842 |
| | Rockies | 1,801 | 1,850 | 1,899 | 1,940 | 1,983 | 2,027 | 2,076 | 2,128 | 2,178 |
| | Desert SW | 4,808 | 4,960 | 5,116 | 5,263 | 5,399 | 5,545 | 5,688 | 5,833 | 5,973 |
| | No. CA | 4,524 | 4,599 | 4,679 | 4,757 | 4,836 | 4,914 | 4,992 | 5,073 | 5,157 |
| | So. CA/MX | 5,868 | 5,945 | 6,044 | 6,146 | 6,264 | 6,353 | 6,465 | 6,574 | 6,704 |
| | Total | 23,909 | 24,400 | 24,905 | 25,393 | 25,878 | 26,371 | 26,877 | 27,389 | 27,936 |
| Load Requirement | Canada | 19,970 | 20,404 | 20,811 | 21,192 | 21,542 | 21,985 | 22,367 | 22,685 | 23,165 |
| | Northwest | 27,208 | 27,504 | 27,871 | 28,211 | 28,518 | 28,885 | 29,256 | 29,644 | 30,125 |
| | Basin | 13,580 | 14,075 | 14,368 | 14,707 | 15,018 | 15,399 | 15,738 | 16,132 | 16,423 |
| | Rockies | 14,701 | 15,125 | 15,518 | 15,867 | 16,221 | 16,573 | 16,965 | 17,379 | 17,772 |
| | Desert SW | 35,687 | 36,843 | 37,991 | 39,086 | 40,094 | 41,175 | 42,224 | 43,332 | 44,359 |
| | No. CA | 31,986 | 32,510 | 33,069 | 33,621 | 34,179 | 34,743 | 35,287 | 35,855 | 36,450 |
| | So. CA/MX | 41,151 | 41,702 | 42,418 | 43,145 | 43,990 | 44,629 | 45,414 | 46,203 | 47,129 |
| | Total | 184,283 | 188,163 | 192,046 | 195,829 | 199,562 | 203,389 | 207,251 | 211,230 | 215,423 |
| Net Base Resource Capacity | Canada | 24,967 | 24,984 | 24,987 | 24,987 | 24,987 | 24,987 | 24,987 | 24,987 | 24,987 |
| | Northwest | 43,609 | 43,609 | 43,701 | 43,714 | 43,727 | 43,727 | 43,727 | 43,727 | 43,727 |
| | Basin | 12,231 | 12,231 | 12,231 | 12,231 | 12,231 | 12,231 | 12,231 | 12,231 | 12,231 |
| | Rockies | 16,752 | 16,752 | 17,502 | 17,776 | 17,776 | 17,776 | 17,776 | 17,776 | 17,776 |
| | Desert SW | 39,873 | 40,081 | 40,481 | 40,481 | 40,481 | 40,481 | 40,481 | 40,481 | 40,481 |
| | No. CA | 30,376 | 30,371 | 30,901 | 30,901 | 30,901 | 30,901 | 30,901 | 30,901 | 30,901 |
| | So. CA/MX | 30,890 | 31,384 | 31,477 | 31,477 | 31,477 | 31,477 | 31,477 | 31,477 | 31,477 |
| | Total | 198,697 | 199,412 | 201,280 | 201,567 | 201,580 | 201,580 | 201,580 | 201,580 | 201,580 |
| Other Outages and De-rates | Canada | -2,138 | -1,980 | -1,980 | -1,980 | -1,980 | -1,980 | -1,980 | -1,980 | -1,980 |
| | Northwest | -1,771 | -1,806 | -1,762 | -1,767 | -1,815 | -1,898 | -1,896 | -1,904 | -1,881 |
| | Basin | 904 | 926 | 930 | 934 | 939 | 936 | 948 | 952 | 951 |
| | Rockies | -66 | -66 | -62 | -64 | -59 | -55 | -53 | -52 | -51 |
| | Desert SW | -215 | -173 | -168 | -165 | -163 | -162 | -162 | -162 | -162 |
| | No. CA | -196 | -196 | -197 | -194 | -192 | -192 | -192 | -191 | -189 |
| | So. CA/MX | -642 | -474 | -474 | -472 | -469 | -468 | -466 | -463 | -460 |
| | Total | -4,126 | -3,769 | -3,712 | -3,710 | -3,739 | -3,819 | -3,801 | -3,800 | -3,771 |
| SAM Net Imports (+) (negative if exporting) | Canada | -609 | -516 | -435 | -328 | -219 | -87 | -47 | 0 | 0 |
| | Northwest | -6,591 | -6,684 | -6,765 | -6,872 | -6,981 | -7,113 | -7,153 | -7,200 | -7,200 |
| | Basin | 446 | 918 | 1,207 | 1,312 | 1,312 | 1,312 | 1,312 | 1,322 | 1,392 |
| | Rockies | -1,985 | -1,605 | -1,922 | -1,999 | -1,999 | -1,999 | -1,999 | -1,999 | -1,999 |
| | Desert SW | -3,971 | -4,009 | -4,151 | -4,186 | -4,240 | -4,186 | -4,132 | -4,078 | -4,025 |
| | No. CA | 1,807 | 2,310 | 2,365 | 2,427 | 2,486 | 2,546 | 2,608 | 2,661 | 2,654 |
| | So. CA/MX | 10,904 | 9,587 | 9,702 | 9,647 | 9,641 | 9,527 | 9,411 | 9,294 | 9,178 |
| | Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Available Resources including Transfers | Canada | 22,220 | 22,488 | 22,572 | 22,679 | 22,788 | 22,920 | 22,960 | 23,007 | 23,007 |
| | Northwest | 35,246 | 35,119 | 35,174 | 35,075 | 34,931 | 34,715 | 34,678 | 34,623 | 34,646 |
| | Basin | 13,580 | 14,075 | 14,368 | 14,476 | 14,481 | 14,479 | 14,491 | 14,505 | 14,574 |
| | Rockies | 14,701 | 15,081 | 15,518 | 15,713 | 15,719 | 15,722 | 15,724 | 15,725 | 15,726 |
| | Desert SW | 35,687 | 35,899 | 36,162 | 36,130 | 36,078 | 36,133 | 36,187 | 36,241 | 36,294 |
| | No. CA | 31,986 | 32,484 | 33,069 | 33,133 | 33,195 | 33,255 | 33,317 | 33,371 | 33,366 |
| | So. CA/MX | 41,151 | 40,496 | 40,704 | 40,651 | 40,649 | 40,536 | 40,422 | 40,308 | 40,195 |
| | Total | 194,571 | 195,642 | 197,568 | 197,858 | 197,841 | 197,761 | 197,779 | 197,779 | 197,809 |
| Power Supply Margin | Canada | 2,250 | 2,084 | 1,761 | 1,487 | 1,246 | 935 | 593 | 322 | -158 |
| | Northwest | 8,038 | 7,615 | 7,303 | 6,864 | 6,413 | 5,830 | 5,422 | 4,979 | 4,521 |
| | Basin | 0 | 0 | 0 | -231 | -537 | -920 | -1,248 | -1,628 | -1,849 |
| | Rockies | 0 | -44 | 0 | -154 | -502 | -851 | -1,241 | -1,653 | -2,045 |
| | Desert SW | 0 | -944 | -1,829 | -2,956 | -4,016 | -5,042 | -6,037 | -7,091 | -8,065 |
| | No. CA | 0 | -26 | 0 | -488 | -984 | -1,488 | -1,970 | -2,484 | -3,084 |
| | So. CA/MX | 0 | -1,206 | -1,714 | -2,494 | -3,341 | -4,093 | -4,992 | -5,895 | -6,934 |
| | Total | 10,288 | 7,479 | 5,522 | 2,029 | -1,721 | -5,628 | -9,472 | -13,451 | -17,614 |

Table 19 - Sub-region Summary - Case #2

| Parameter | Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| Firm Demand | Canada | 21,916 | 22,347 | 22,823 | 23,139 | 23,494 | 23,961 | 24,330 | 24,715 | 25,188 |
| | Northwest | 29,237 | 29,693 | 29,989 | 30,274 | 30,671 | 31,036 | 31,429 | 31,788 | 32,136 |
| | Basin | 9,568 | 10,045 | 10,290 | 10,444 | 10,712 | 10,954 | 11,186 | 11,409 | 11,549 |
| | Rockies | 10,751 | 11,051 | 11,352 | 11,599 | 11,854 | 12,114 | 12,396 | 12,679 | 12,947 |
| | Desert SW | 19,092 | 19,691 | 20,327 | 20,847 | 21,382 | 21,944 | 22,480 | 23,077 | 23,641 |
| | No. CA | 18,082 | 18,267 | 18,459 | 18,653 | 18,848 | 19,046 | 19,237 | 19,430 | 19,618 |
| | So. CA/MX | 24,297 | 24,579 | 24,846 | 25,091 | 25,292 | 25,611 | 25,895 | 26,187 | 26,437 |
| | Total | 132,943 | 135,673 | 138,086 | 140,047 | 142,253 | 144,666 | 146,953 | 149,285 | 151,516 |
| Non-Firm Demand | Canada | 299 | 299 | 299 | 299 | 299 | 299 | 299 | 299 | 299 |
| | Northwest | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Basin | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| | Rockies | 159 | 161 | 162 | 163 | 164 | 166 | 167 | 168 | 169 |
| | Desert SW | 306 | 340 | 344 | 359 | 364 | 369 | 374 | 404 | 408 |
| | No. CA | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 |
| | So. CA/MX | 977 | 1,004 | 1,031 | 1,082 | 1,127 | 1,164 | 1,200 | 1,230 | 1,256 |
| | Total | 2,687 | 2,750 | 2,782 | 2,849 | 2,900 | 2,944 | 2,986 | 3,047 | 3,078 |
| Building Block Reserve Requirement | Canada | 2,796 | 2,851 | 2,912 | 2,952 | 2,998 | 3,057 | 3,104 | 3,154 | 3,214 |
| | Northwest | 4,780 | 4,854 | 4,903 | 4,949 | 5,014 | 5,073 | 5,138 | 5,197 | 5,254 |
| | Basin | 1,292 | 1,357 | 1,389 | 1,408 | 1,447 | 1,479 | 1,511 | 1,540 | 1,559 |
| | Rockies | 1,653 | 1,697 | 1,745 | 1,783 | 1,821 | 1,860 | 1,906 | 1,948 | 1,991 |
| | Desert SW | 2,794 | 2,883 | 2,976 | 3,052 | 3,130 | 3,212 | 3,291 | 3,377 | 3,460 |
| | No. CA | 2,345 | 2,367 | 2,391 | 2,414 | 2,439 | 2,464 | 2,487 | 2,512 | 2,535 |
| | So. CA/MX | 3,282 | 3,321 | 3,360 | 3,399 | 3,430 | 3,476 | 3,518 | 3,559 | 3,595 |
| | Total | 18,942 | 19,330 | 19,676 | 19,957 | 20,279 | 20,621 | 20,955 | 21,287 | 21,608 |
| Load Requirement | Canada | 25,011 | 25,497 | 26,034 | 26,390 | 26,791 | 27,317 | 27,733 | 28,168 | 28,701 |
| | Northwest | 34,017 | 34,547 | 34,892 | 35,223 | 35,685 | 36,109 | 36,567 | 36,985 | 37,390 |
| | Basin | 11,060 | 11,602 | 11,879 | 12,052 | 12,359 | 12,633 | 12,897 | 13,149 | 13,308 |
| | Rockies | 12,563 | 12,909 | 13,259 | 13,545 | 13,839 | 14,140 | 14,469 | 14,795 | 15,107 |
| | Desert SW | 22,192 | 22,914 | 23,647 | 24,258 | 24,876 | 25,525 | 26,145 | 26,858 | 27,509 |
| | No. CA | 21,173 | 21,380 | 21,596 | 21,813 | 22,033 | 22,256 | 22,470 | 22,688 | 22,899 |
| | So. CA/MX | 28,556 | 28,904 | 29,237 | 29,572 | 29,849 | 30,251 | 30,613 | 30,976 | 31,288 |
| | Total | 154,572 | 157,753 | 160,544 | 162,853 | 165,432 | 168,231 | 170,894 | 173,619 | 176,202 |
| Net Base Resource Capacity | Canada | 24,099 | 24,099 | 24,099 | 24,099 | 24,099 | 24,099 | 24,099 | 24,099 | 24,099 |
| | Northwest | 44,552 | 44,566 | 44,579 | 44,592 | 44,605 | 44,605 | 44,605 | 44,605 | 44,605 |
| | Basin | 11,975 | 11,975 | 11,975 | 11,975 | 11,975 | 11,975 | 11,975 | 11,975 | 11,975 |
| | Rockies | 17,138 | 17,138 | 18,200 | 18,200 | 18,200 | 18,200 | 18,200 | 18,200 | 18,200 |
| | Desert SW | 40,963 | 41,571 | 41,571 | 41,571 | 41,571 | 41,571 | 41,571 | 41,571 | 41,571 |
| | No. CA | 30,427 | 30,907 | 30,957 | 30,957 | 30,957 | 30,957 | 30,957 | 30,957 | 30,957 |
| | So. CA/MX | 30,867 | 31,361 | 31,454 | 31,454 | 31,454 | 31,454 | 31,454 | 31,454 | 31,454 |
| | Total | 200,021 | 201,617 | 202,835 | 202,848 | 202,860 | 202,860 | 202,860 | 202,860 | 202,860 |
| Other Outages and De-rates | Canada | -186 | -190 | -192 | -196 | -199 | -203 | -205 | -206 | -201 |
| | Northwest | 1,159 | 1,383 | 1,298 | 1,201 | 1,300 | 1,118 | 979 | 919 | 785 |
| | Basin | -1,389 | -1,721 | -1,574 | -1,546 | -1,493 | -1,404 | -1,431 | -1,217 | -1,097 |
| | Rockies | -111 | -121 | -120 | -125 | -127 | -123 | -144 | -121 | -127 |
| | Desert SW | -570 | -613 | -872 | -834 | -548 | -787 | -1,243 | -758 | -1,124 |
| | No. CA | -1,196 | -1,220 | -1,196 | -1,196 | -1,196 | -1,196 | -1,196 | -1,196 | -1,196 |
| | So. CA/MX | -2,629 | -2,612 | -2,742 | -2,978 | -2,682 | -2,589 | -2,601 | -2,612 | -2,629 |
| | Total | -4,922 | -5,094 | -5,398 | -5,673 | -4,946 | -5,184 | -5,841 | -5,191 | -5,590 |
| SAM Net Imports (+) (negative if exporting) | Canada | 1,042 | 1,207 | 1,326 | 1,480 | 1,638 | 1,827 | 1,883 | 2,000 | 2,000 |
| | Northwest | -1,042 | -107 | -1,326 | -1,480 | -1,638 | -1,827 | -1,883 | -2,000 | -2,000 |
| | Basin | 826 | 1,349 | 1,479 | 1,623 | 1,878 | 2,062 | 2,354 | 2,392 | 2,431 |
| | Rockies | -2,665 | -2,731 | -2,766 | -2,731 | -2,867 | -2,896 | -2,731 | -2,731 | -2,731 |
| | Desert SW | -3,031 | -2,817 | -1,845 | -1,783 | -1,936 | -2,210 | -2,385 | -2,154 | -1,259 |
| | No. CA | 0 | 0 | -125 | -608 | -749 | -935 | -1,527 | -2,064 | -3,151 |
| | So. CA/MX | 4,870 | 3,100 | 3,258 | 3,498 | 3,674 | 3,979 | 4,289 | 4,557 | 4,709 |
| | Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Available Resources including Transfers | Canada | 24,955 | 25,116 | 25,233 | 25,383 | 25,538 | 25,723 | 25,778 | 25,893 | 25,898 |
| | Northwest | 44,669 | 45,842 | 44,551 | 44,313 | 44,266 | 43,895 | 43,700 | 43,524 | 43,390 |
| | Basin | 11,411 | 11,602 | 11,879 | 12,052 | 12,359 | 12,633 | 12,897 | 13,149 | 13,308 |
| | Rockies | 14,362 | 14,286 | 15,315 | 15,344 | 15,206 | 15,182 | 15,325 | 15,349 | 15,342 |
| | Desert SW | 37,362 | 38,141 | 38,853 | 38,954 | 39,087 | 38,574 | 37,943 | 38,659 | 39,188 |
| | No. CA | 29,231 | 29,687 | 29,636 | 29,153 | 29,012 | 28,826 | 28,234 | 27,697 | 26,611 |
| | So. CA/MX | 33,108 | 31,848 | 31,970 | 31,975 | 32,446 | 32,844 | 33,142 | 33,399 | 33,535 |
| | Total | 195,099 | 196,523 | 197,436 | 197,175 | 197,914 | 197,677 | 197,020 | 197,670 | 197,270 |
| Power Supply Margin | Canada | -56 | -381 | -801 | -1,007 | -1,253 | -1,594 | -1,955 | -2,275 | -2,803 |
| | Northwest | 10,652 | 11,295 | 9,659 | 9,090 | 8,581 | 7,786 | 7,133 | 6,539 | 6,000 |
| | Basin | 351 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Rockies | 1,800 | 1,378 | 2,056 | 1,800 | 1,368 | 1,042 | 856 | 554 | 235 |
| | Desert SW | 15,170 | 15,227 | 15,206 | 14,696 | 14,211 | 13,049 | 11,798 | 11,801 | 11,679 |
| | No. CA | 8,058 | 8,307 | 8,040 | 7,340 | 6,979 | 6,570 | 5,764 | 5,009 | 3,712 |
| | So. CA/MX | 4,552 | 2,944 | 2,733 | 2,403 | 2,597 | 2,593 | 2,529 | 2,423 | 2,247 |
| | Total | 40,527 | 38,770 | 36,892 | 34,322 | 32,482 | 29,446 | 26,126 | 24,051 | 21,068 |

Table 20 - Sub-region Summary - Case #3

| Parameter | Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| Firm Demand | Canada | 17,568 | 17,955 | 18,319 | 18,659 | 18,972 | 19,367 | 19,709 | 19,993 | 20,422 |
| | Northwest | 23,922 | 24,183 | 24,505 | 24,804 | 25,074 | 25,397 | 25,723 | 26,064 | 26,487 |
| | Basin | 11,850 | 12,289 | 12,549 | 12,850 | 13,126 | 13,463 | 13,763 | 14,113 | 14,370 |
| | Rockies | 12,635 | 12,994 | 13,323 | 13,617 | 13,917 | 14,216 | 14,562 | 14,934 | 15,286 |
| | Desert SW | 30,573 | 31,543 | 32,531 | 33,464 | 34,331 | 35,261 | 36,162 | 37,095 | 37,978 |
| | No. CA | 26,148 | 26,595 | 27,074 | 27,547 | 28,025 | 28,509 | 28,975 | 29,461 | 29,970 |
| | So. CA/MX | 33,899 | 34,346 | 34,936 | 35,510 | 36,192 | 36,705 | 37,342 | 37,992 | 38,762 |
| | Total | 156,595 | 159,905 | 163,237 | 166,451 | 169,637 | 172,918 | 176,236 | 179,652 | 183,275 |
| Non-Firm Demand | Canada | 299 | 299 | 299 | 299 | 299 | 299 | 299 | 299 | 299 |
| | Northwest | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Basin | 211 | 211 | 211 | 211 | 211 | 211 | 211 | 211 | 211 |
| | Rockies | 265 | 281 | 296 | 310 | 321 | 330 | 327 | 317 | 308 |
| | Desert SW | 306 | 340 | 344 | 359 | 364 | 369 | 374 | 404 | 408 |
| | No. CA | 1,314 | 1,316 | 1,316 | 1,317 | 1,318 | 1,320 | 1,320 | 1,321 | 1,323 |
| | So. CA/MX | 1,384 | 1,411 | 1,438 | 1,489 | 1,534 | 1,571 | 1,607 | 1,637 | 1,663 |
| | Total | 3,779 | 3,858 | 3,904 | 3,985 | 4,047 | 4,100 | 4,138 | 4,189 | 4,212 |
| Building Block Reserve Requirement | Canada | 2,103 | 2,150 | 2,193 | 2,234 | 2,271 | 2,319 | 2,359 | 2,393 | 2,444 |
| | Northwest | 3,286 | 3,321 | 3,366 | 3,407 | 3,444 | 3,488 | 3,533 | 3,580 | 3,638 |
| | Basin | 1,519 | 1,575 | 1,608 | 1,646 | 1,681 | 1,725 | 1,764 | 1,808 | 1,842 |
| | Rockies | 1,801 | 1,850 | 1,899 | 1,940 | 1,983 | 2,027 | 2,076 | 2,128 | 2,178 |
| | Desert SW | 4,808 | 4,960 | 5,116 | 5,263 | 5,399 | 5,545 | 5,688 | 5,833 | 5,973 |
| | No. CA | 4,524 | 4,599 | 4,679 | 4,757 | 4,836 | 4,914 | 4,992 | 5,073 | 5,157 |
| | So. CA/MX | 5,868 | 5,945 | 6,044 | 6,146 | 6,264 | 6,353 | 6,465 | 6,574 | 6,704 |
| | Total | 23,909 | 24,400 | 24,905 | 25,393 | 25,878 | 26,371 | 26,877 | 27,389 | 27,936 |
| Load Requirement | Canada | 19,970 | 20,404 | 20,811 | 21,192 | 21,542 | 21,985 | 22,367 | 22,685 | 23,165 |
| | Northwest | 27,208 | 27,504 | 27,871 | 28,211 | 28,518 | 28,885 | 29,256 | 29,644 | 30,125 |
| | Basin | 13,580 | 14,075 | 14,368 | 14,707 | 15,018 | 15,399 | 15,738 | 16,132 | 16,423 |
| | Rockies | 14,701 | 15,125 | 15,518 | 15,867 | 16,221 | 16,573 | 16,965 | 17,379 | 17,772 |
| | Desert SW | 35,687 | 36,843 | 37,991 | 39,086 | 40,094 | 41,175 | 42,224 | 43,332 | 44,359 |
| | No. CA | 31,986 | 32,510 | 33,069 | 33,621 | 34,179 | 34,743 | 35,287 | 35,855 | 36,450 |
| | So. CA/MX | 41,151 | 41,702 | 42,418 | 43,145 | 43,990 | 44,629 | 45,414 | 46,203 | 47,129 |
| | Total | 184,283 | 188,163 | 192,046 | 195,829 | 199,562 | 203,389 | 207,251 | 211,230 | 215,423 |
| Net Base Resource Capacity | Canada | 24,967 | 25,099 | 25,162 | 26,112 | 26,112 | 26,112 | 26,112 | 26,112 | 26,112 |
| | Northwest | 43,676 | 43,706 | 43,798 | 43,811 | 43,824 | 43,824 | 43,824 | 43,824 | 43,824 |
| | Basin | 12,396 | 12,396 | 12,396 | 12,396 | 12,396 | 12,396 | 12,396 | 12,396 | 12,396 |
| | Rockies | 16,879 | 16,879 | 17,629 | 17,903 | 17,903 | 17,903 | 17,903 | 17,903 | 17,903 |
| | Desert SW | 39,873 | 40,081 | 40,481 | 40,481 | 40,481 | 40,481 | 40,481 | 40,481 | 40,481 |
| | No. CA | 30,983 | 32,213 | 32,861 | 32,861 | 32,861 | 32,861 | 32,861 | 32,861 | 32,861 |
| | So. CA/MX | 30,890 | 31,955 | 33,523 | 34,133 | 34,133 | 34,133 | 34,133 | 34,133 | 34,133 |
| | Total | 199,664 | 202,329 | 205,850 | 207,698 | 207,710 | 207,710 | 207,710 | 207,710 | 207,710 |
| Other Outages and De-rates | Canada | -2,138 | -1,979 | -1,980 | -1,980 | -1,980 | -1,980 | -1,980 | -1,980 | -1,980 |
| | Northwest | -1,141 | -1,651 | -1,595 | -1,782 | -1,830 | -1,913 | -1,911 | -1,917 | -1,890 |
| | Basin | 322 | 786 | 784 | 924 | 929 | 932 | 944 | 949 | 953 |
| | Rockies | -49 | -74 | -65 | -67 | -61 | -56 | -53 | -52 | -51 |
| | Desert SW | -207 | -224 | -225 | -218 | -183 | -168 | -164 | -162 | -162 |
| | No. CA | -192 | -188 | -184 | -192 | -193 | -195 | -192 | -191 | -191 |
| | So. CA/MX | -648 | -524 | -504 | -495 | -489 | -491 | -483 | -476 | -474 |
| | Total | -4,053 | -3,852 | -3,769 | -3,811 | -3,806 | -3,870 | -3,839 | -3,830 | -3,795 |
| SAM Net Imports (+) (negative if exporting) | Canada | -609 | -597 | -525 | -918 | -809 | -677 | -637 | -532 | -392 |
| | Northwest | -6,248 | -6,487 | -6,467 | -6,282 | -6,391 | -6,523 | -6,563 | -6,668 | -6,808 |
| | Basin | 862 | 893 | 1,188 | 1,387 | 1,404 | 1,312 | 1,312 | 1,312 | 1,312 |
| | Rockies | -2,130 | -1,681 | -2,046 | -1,975 | -1,999 | -1,999 | -1,999 | -1,999 | -1,999 |
| | Desert SW | -3,979 | -3,015 | -2,028 | -2,402 | -3,534 | -3,967 | -4,069 | -4,078 | -4,025 |
| | No. CA | 1,195 | 484 | 392 | 952 | 1,510 | 1,663 | 1,725 | 1,788 | 1,851 |
| | So. CA/MX | 10,909 | 10,402 | 9,486 | 9,237 | 9,819 | 10,191 | 10,231 | 10,177 | 10,061 |
| | Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Available Resources including Transfers | Canada | 22,220 | 22,523 | 22,657 | 23,214 | 23,323 | 23,455 | 23,495 | 23,600 | 23,740 |
| | Northwest | 36,286 | 35,568 | 35,737 | 35,747 | 35,603 | 35,388 | 35,350 | 35,239 | 35,125 |
| | Basin | 13,580 | 14,075 | 14,368 | 14,707 | 14,729 | 14,640 | 14,652 | 14,657 | 14,661 |
| | Rockies | 14,701 | 15,125 | 15,518 | 15,861 | 15,843 | 15,848 | 15,851 | 15,852 | 15,853 |
| | Desert SW | 35,687 | 36,843 | 38,228 | 37,861 | 36,764 | 36,346 | 36,248 | 36,241 | 36,294 |
| | No. CA | 31,986 | 32,510 | 33,069 | 33,621 | 34,179 | 34,330 | 34,394 | 34,458 | 34,521 |
| | So. CA/MX | 41,151 | 41,833 | 42,505 | 42,875 | 43,462 | 43,833 | 43,881 | 43,834 | 43,721 |
| | Total | 195,611 | 198,477 | 202,081 | 203,887 | 203,904 | 203,840 | 203,871 | 203,880 | 203,915 |
| Power Supply Margin | Canada | 2,250 | 2,119 | 1,846 | 2,022 | 1,781 | 1,470 | 1,128 | 915 | 575 |
| | Northwest | 9,078 | 8,064 | 7,866 | 7,536 | 7,085 | 6,503 | 6,094 | 5,595 | 5,000 |
| | Basin | 0 | 0 | 0 | 0 | -289 | -759 | -1,087 | -1,476 | -1,762 |
| | Rockies | 0 | 0 | 0 | -5 | -377 | -724 | -1,114 | -1,526 | -1,918 |
| | Desert SW | 0 | 0 | 237 | -1,225 | -3,330 | -4,829 | -5,976 | -7,091 | -8,065 |
| | No. CA | 0 | 0 | 0 | 0 | 0 | -413 | -893 | -1,397 | -1,929 |
| | So. CA/MX | 0 | 131 | 87 | -270 | -528 | -796 | -1,533 | -2,369 | -3,408 |
| | Total | 11,328 | 10,314 | 10,035 | 8,058 | 4,342 | 451 | -3,380 | -7,350 | -11,508 |

Table 21 - Sub-region Summary - Case #4

| Parameter | Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| Firm Demand | Canada | 21,916 | 22,347 | 22,823 | 23,139 | 23,494 | 23,961 | 24,330 | 24,715 | 25,188 |
| | Northwest | 29,237 | 29,693 | 29,989 | 30,274 | 30,671 | 31,036 | 31,429 | 31,788 | 32,136 |
| | Basin | 9,568 | 10,045 | 10,290 | 10,444 | 10,712 | 10,954 | 11,186 | 11,409 | 11,549 |
| | Rockies | 10,751 | 11,051 | 11,352 | 11,599 | 11,854 | 12,114 | 12,396 | 12,679 | 12,947 |
| | Desert SW | 19,092 | 19,691 | 20,327 | 20,847 | 21,382 | 21,944 | 22,480 | 23,077 | 23,641 |
| | No. CA | 18,082 | 18,267 | 18,459 | 18,653 | 18,848 | 19,046 | 19,237 | 19,430 | 19,618 |
| | So. CA/MX | 24,297 | 24,579 | 24,846 | 25,091 | 25,292 | 25,611 | 25,895 | 26,187 | 26,437 |
| | Total | 132,943 | 135,673 | 138,086 | 140,047 | 142,253 | 144,666 | 146,953 | 149,285 | 151,516 |
| Non-Firm Demand | Canada | 299 | 299 | 299 | 299 | 299 | 299 | 299 | 299 | 299 |
| | Northwest | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Basin | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| | Rockies | 159 | 161 | 162 | 163 | 164 | 166 | 167 | 168 | 169 |
| | Desert SW | 306 | 340 | 344 | 359 | 364 | 369 | 374 | 404 | 408 |
| | No. CA | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 | 746 |
| | So. CA/MX | 977 | 1,004 | 1,031 | 1,082 | 1,127 | 1,164 | 1,200 | 1,230 | 1,256 |
| | Total | 2,687 | 2,750 | 2,782 | 2,849 | 2,900 | 2,944 | 2,986 | 3,047 | 3,078 |
| Building Block Reserve Requirement | Canada | 2,796 | 2,851 | 2,912 | 2,952 | 2,998 | 3,057 | 3,104 | 3,154 | 3,214 |
| | Northwest | 4,780 | 4,854 | 4,903 | 4,949 | 5,014 | 5,073 | 5,138 | 5,197 | 5,254 |
| | Basin | 1,292 | 1,357 | 1,389 | 1,408 | 1,447 | 1,479 | 1,511 | 1,540 | 1,559 |
| | Rockies | 1,653 | 1,697 | 1,745 | 1,783 | 1,821 | 1,860 | 1,906 | 1,948 | 1,991 |
| | Desert SW | 2,794 | 2,883 | 2,976 | 3,052 | 3,130 | 3,212 | 3,291 | 3,377 | 3,460 |
| | No. CA | 2,345 | 2,367 | 2,391 | 2,414 | 2,439 | 2,464 | 2,487 | 2,512 | 2,535 |
| | So. CA/MX | 3,282 | 3,321 | 3,360 | 3,399 | 3,430 | 3,476 | 3,518 | 3,559 | 3,595 |
| | Total | 18,942 | 19,330 | 19,676 | 19,957 | 20,279 | 20,621 | 20,955 | 21,287 | 21,608 |
| Load Requirement | Canada | 25,011 | 25,497 | 26,034 | 26,390 | 26,791 | 27,317 | 27,733 | 28,168 | 28,701 |
| | Northwest | 34,017 | 34,547 | 34,892 | 35,223 | 35,685 | 36,109 | 36,567 | 36,985 | 37,390 |
| | Basin | 11,060 | 11,602 | 11,879 | 12,052 | 12,359 | 12,633 | 12,897 | 13,149 | 13,308 |
| | Rockies | 12,563 | 12,909 | 13,259 | 13,545 | 13,839 | 14,140 | 14,469 | 14,795 | 15,107 |
| | Desert SW | 22,192 | 22,914 | 23,647 | 24,258 | 24,876 | 25,525 | 26,145 | 26,858 | 27,509 |
| | No. CA | 21,173 | 21,380 | 21,596 | 21,813 | 22,033 | 22,256 | 22,470 | 22,688 | 22,899 |
| | So. CA/MX | 28,556 | 28,904 | 29,237 | 29,572 | 29,849 | 30,251 | 30,613 | 30,976 | 31,288 |
| | Total | 154,572 | 157,753 | 160,544 | 162,853 | 165,432 | 168,231 | 170,894 | 173,619 | 176,202 |
| Net Base Resource Capacity | Canada | 24,184 | 24,214 | 24,774 | 25,224 | 25,224 | 25,224 | 25,224 | 25,224 | 25,224 |
| | Northwest | 44,649 | 44,663 | 44,676 | 44,689 | 44,702 | 44,702 | 44,702 | 44,702 | 44,702 |
| | Basin | 12,153 | 12,153 | 12,153 | 12,153 | 12,153 | 12,153 | 12,153 | 12,153 | 12,153 |
| | Rockies | 17,265 | 17,265 | 18,327 | 18,327 | 18,327 | 18,327 | 18,327 | 18,327 | 18,327 |
| | Desert SW | 40,963 | 41,571 | 41,571 | 41,571 | 41,571 | 41,571 | 41,571 | 41,571 | 41,571 |
| | No. CA | 31,154 | 32,868 | 32,918 | 32,918 | 32,918 | 32,918 | 32,918 | 32,918 | 32,918 |
| | So. CA/MX | 30,867 | 33,407 | 34,110 | 34,110 | 34,110 | 34,110 | 34,110 | 34,110 | 34,110 |
| | Total | 201,234 | 206,141 | 208,528 | 208,991 | 209,004 | 209,004 | 209,004 | 209,004 | 209,004 |
| Other Outages and De-rates | Canada | -185 | -189 | -179 | -182 | -186 | -190 | -191 | -195 | -199 |
| | Northwest | 1,159 | 1,233 | 1,225 | 1,259 | 1,450 | 1,400 | 1,164 | 1,104 | 969 |
| | Basin | -1,385 | -1,715 | -1,728 | -1,730 | -1,714 | -1,683 | -1,609 | -1,395 | -1,275 |
| | Rockies | -112 | -125 | -119 | -122 | -128 | -124 | -144 | -120 | -125 |
| | Desert SW | -570 | -614 | -874 | -848 | -589 | -847 | -1,274 | -773 | -1,120 |
| | No. CA | -1,195 | -1,221 | -1,197 | -1,195 | -1,195 | -1,195 | -1,195 | -1,196 | -1,196 |
| | So. CA/MX | -2,629 | -2,630 | -2,767 | -2,990 | -2,688 | -2,584 | -2,583 | -2,586 | -2,584 |
| | Total | -4,916 | -5,260 | -5,639 | -5,810 | -5,050 | -5,223 | -5,834 | -5,161 | -5,529 |
| SAM Net Imports (+) (negative if exporting) | Canada | 1,012 | 1,176 | 723 | 876 | 1,035 | 1,224 | 1,280 | 1,433 | 1,633 |
| | Northwest | -1,012 | 2,134 | 2,438 | 898 | -90 | -1,224 | -1,280 | -1,433 | -1,633 |
| | Basin | 643 | 1,231 | 1,521 | 1,629 | 1,920 | 2,163 | 2,354 | 2,392 | 2,431 |
| | Rockies | -2,483 | -2,639 | -2,731 | -2,731 | -2,731 | -2,952 | -2,731 | -2,731 | -2,731 |
| | Desert SW | -3,031 | -2,653 | -1,807 | -1,303 | -830 | -226 | -1,020 | -1,428 | -1,236 |
| | No. CA | 0 | -1,148 | -982 | -766 | -675 | -654 | -634 | -614 | -593 |
| | So. CA/MX | 4,870 | 1,899 | 838 | 1,397 | 1,371 | 1,669 | 2,031 | 2,381 | 2,129 |
| | Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Available Resources including Transfers | Canada | 25,011 | 25,201 | 25,318 | 25,918 | 26,073 | 26,258 | 26,313 | 26,462 | 26,658 |
| | Northwest | 44,796 | 48,030 | 48,339 | 46,847 | 46,062 | 44,878 | 44,585 | 44,373 | 44,038 |
| | Basin | 11,411 | 11,668 | 11,945 | 12,052 | 12,359 | 12,633 | 12,897 | 13,149 | 13,308 |
| | Rockies | 14,671 | 14,502 | 15,477 | 15,474 | 15,468 | 15,250 | 15,452 | 15,477 | 15,472 |
| | Desert SW | 37,362 | 38,304 | 38,890 | 39,419 | 40,151 | 40,498 | 39,277 | 39,370 | 39,215 |
| | No. CA | 29,958 | 30,499 | 30,739 | 30,956 | 31,047 | 31,068 | 31,088 | 31,108 | 31,129 |
| | So. CA/MX | 33,108 | 32,677 | 32,181 | 32,516 | 32,793 | 33,195 | 33,557 | 33,905 | 33,654 |
| | Total | 196,318 | 200,881 | 202,889 | 203,182 | 203,954 | 203,780 | 203,170 | 203,843 | 203,475 |
| Power Supply Margin | Canada | 0 | -296 | -716 | -472 | -718 | -1,059 | -1,420 | -1,706 | -2,043 |
| | Northwest | 10,779 | 13,483 | 13,447 | 11,624 | 10,377 | 8,769 | 8,018 | 7,388 | 6,648 |
| | Basin | 351 | 66 | 66 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Rockies | 2,108 | 1,593 | 2,218 | 1,929 | 1,630 | 1,111 | 983 | 682 | 365 |
| | Desert SW | 15,170 | 15,390 | 15,243 | 15,161 | 15,275 | 14,973 | 13,132 | 12,512 | 11,706 |
| | No. CA | 8,785 | 9,119 | 9,143 | 9,143 | 9,014 | 8,812 | 8,618 | 8,420 | 8,230 |
| | So. CA/MX | 4,552 | 3,773 | 2,944 | 2,944 | 2,944 | 2,944 | 2,944 | 2,929 | 2,366 |
| | Total | 41,746 | 43,128 | 42,345 | 40,329 | 38,522 | 35,549 | 32,276 | 30,224 | 27,273 |

Table 22 - Sub-region Summary - Case #5

| Parameter | Sub-region | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|---|---|---|---|---|---|
| Firm Demand | Canada | 17,568 | 17,955 | 18,319 | 18,659 | 18,972 | 19,367 | 19,709 | 19,993 | 20,422 |
| | Northwest | 23,922 | 24,183 | 24,505 | 24,804 | 25,074 | 25,397 | 25,723 | 26,064 | 26,487 |
| | Basin | 11,850 | 12,289 | 12,549 | 12,850 | 13,126 | 13,463 | 13,763 | 14,113 | 14,370 |
| | Rockies | 12,635 | 12,994 | 13,323 | 13,617 | 13,917 | 14,216 | 14,562 | 14,934 | 15,286 |
| | Desert SW | 30,573 | 31,543 | 32,531 | 33,464 | 34,331 | 35,261 | 36,162 | 37,095 | 37,978 |
| | No. CA | 26,148 | 26,595 | 27,074 | 27,547 | 28,025 | 28,509 | 28,975 | 29,461 | 29,970 |
| | So. CA/MX | 33,899 | 34,346 | 34,936 | 35,510 | 36,192 | 36,705 | 37,342 | 37,992 | 38,762 |
| | Total | 156,595 | 159,905 | 163,237 | 166,451 | 169,637 | 172,918 | 176,236 | 179,652 | 183,275 |
| Non-Firm Demand | Canada | 299 | 299 | 299 | 299 | 299 | 299 | 299 | 299 | 299 |
| | Northwest | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Basin | 211 | 211 | 211 | 211 | 211 | 211 | 211 | 211 | 211 |
| | Rockies | 265 | 281 | 296 | 310 | 321 | 330 | 327 | 317 | 308 |
| | Desert SW | 306 | 340 | 344 | 359 | 364 | 369 | 374 | 404 | 408 |
| | No. CA | 1,314 | 1,316 | 1,316 | 1,317 | 1,318 | 1,320 | 1,320 | 1,321 | 1,323 |
| | So. CA/MX | 1,384 | 1,411 | 1,438 | 1,489 | 1,534 | 1,571 | 1,607 | 1,637 | 1,663 |
| | Total | 3,779 | 3,858 | 3,904 | 3,985 | 4,047 | 4,100 | 4,138 | 4,189 | 4,212 |
| Demand Escalation (or assumed reserve margin) | Canada | 2,635 | 2,693 | 2,748 | 2,799 | 2,846 | 2,905 | 2,956 | 2,999 | 3,063 |
| | Northwest | 3,588 | 3,627 | 3,676 | 3,721 | 3,761 | 3,810 | 3,858 | 3,910 | 3,973 |
| | Basin | 1,778 | 1,844 | 1,883 | 1,927 | 1,969 | 2,020 | 2,065 | 2,118 | 2,156 |
| | Rockies | 1,895 | 1,949 | 1,998 | 2,043 | 2,087 | 2,132 | 2,184 | 2,239 | 2,292 |
| | Desert SW | 4,586 | 4,731 | 4,880 | 5,020 | 5,150 | 5,289 | 5,424 | 5,564 | 5,697 |
| | No. CA | 4,119 | 4,187 | 4,259 | 4,330 | 4,402 | 4,475 | 4,544 | 4,618 | 4,694 |
| | So. CA/MX | 5,293 | 5,363 | 5,456 | 5,550 | 5,658 | 5,741 | 5,843 | 5,944 | 6,063 |
| | Total | 23,894 | 24,395 | 24,899 | 25,389 | 25,873 | 26,371 | 26,874 | 27,392 | 27,939 |
| Load Requirement | Canada | 20,502 | 20,947 | 21,366 | 21,757 | 22,117 | 22,571 | 22,964 | 23,291 | 23,784 |
| | Northwest | 27,510 | 27,810 | 28,181 | 28,525 | 28,835 | 29,207 | 29,581 | 29,974 | 30,460 |
| | Basin | 13,839 | 14,344 | 14,643 | 14,988 | 15,306 | 15,694 | 16,039 | 16,442 | 16,737 |
| | Rockies | 14,795 | 15,224 | 15,617 | 15,970 | 16,325 | 16,678 | 17,073 | 17,490 | 17,886 |
| | Desert SW | 35,465 | 36,614 | 37,755 | 38,843 | 39,845 | 40,919 | 41,960 | 43,063 | 44,083 |
| | No. CA | 31,581 | 32,098 | 32,649 | 33,194 | 33,745 | 34,304 | 34,839 | 35,400 | 35,987 |
| | So. CA/MX | 40,576 | 41,120 | 41,830 | 42,549 | 43,384 | 44,017 | 44,792 | 45,573 | 46,488 |
| | Total | 184,268 | 188,158 | 192,040 | 195,825 | 199,557 | 203,389 | 207,248 | 211,233 | 215,426 |
| Net Base Resource Capacity | Canada | 24,967 | 24,984 | 24,987 | 24,987 | 24,987 | 24,987 | 24,987 | 24,987 | 24,987 |
| | Northwest | 43,609 | 43,609 | 43,701 | 43,714 | 43,727 | 43,727 | 43,727 | 43,727 | 43,727 |
| | Basin | 12,231 | 12,231 | 12,231 | 12,231 | 12,231 | 12,231 | 12,231 | 12,231 | 12,231 |
| | Rockies | 16,752 | 16,752 | 17,502 | 17,776 | 17,776 | 17,776 | 17,776 | 17,776 | 17,776 |
| | Desert SW | 39,873 | 40,081 | 40,481 | 40,481 | 40,481 | 40,481 | 40,481 | 40,481 | 40,481 |
| | No. CA | 30,376 | 30,371 | 30,901 | 30,901 | 30,901 | 30,901 | 30,901 | 30,901 | 30,901 |
| | So. CA/MX | 30,890 | 31,384 | 31,477 | 31,477 | 31,477 | 31,477 | 31,477 | 31,477 | 31,477 |
| | Total | 198,697 | 199,412 | 201,280 | 201,567 | 201,580 | 201,580 | 201,580 | 201,580 | 201,580 |
| Other Outages and De-rates | Canada | -2,138 | -1,980 | -1,980 | -1,980 | -1,980 | -1,980 | -1,980 | -1,980 | -1,980 |
| | Northwest | -1,138 | -1,800 | -1,756 | -1,762 | -1,810 | -1,897 | -1,896 | -1,905 | -1,881 |
| | Basin | 302 | 923 | 927 | 939 | 944 | 941 | 952 | 951 | 952 |
| | Rockies | -52 | -60 | -59 | -63 | -57 | -55 | -53 | -51 | -51 |
| | Desert SW | -200 | -176 | -174 | -169 | -163 | -165 | -163 | -162 | -162 |
| | No. CA | -192 | -193 | -193 | -196 | -194 | -192 | -192 | -188 | -188 |
| | So. CA/MX | -641 | -489 | -481 | -473 | -471 | -469 | -467 | -465 | -462 |
| | Total | -4,059 | -3,776 | -3,716 | -3,703 | -3,732 | -3,816 | -3,798 | -3,800 | -3,772 |
| SAM Net Imports (+) (negative if exporting) | Canada | -362 | -266 | -183 | -73 | 0 | 0 | 0 | 0 | 0 |
| | Northwest | -6,555 | -6,934 | -7,017 | -7,127 | -7,200 | -7,200 | -7,200 | -7,200 | -7,200 |
| | Basin | 1,306 | 1,190 | 1,412 | 1,312 | 1,312 | 1,312 | 1,312 | 1,395 | 1,412 |
| | Rockies | -1,905 | -1,781 | -1,999 | -1,999 | -1,999 | -1,999 | -1,999 | -1,999 | -1,999 |
| | Desert SW | -4,209 | -3,917 | -3,918 | -4,088 | -4,207 | -4,104 | -4,123 | -4,088 | -4,035 |
| | No. CA | 1,398 | 1,920 | 1,940 | 2,378 | 2,437 | 2,497 | 2,557 | 2,536 | 2,582 |
| | So. CA/MX | 10,327 | 9,788 | 9,765 | 9,597 | 9,657 | 9,495 | 9,452 | 9,356 | 9,241 |
| | Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Available Resources | Canada | 22,467 | 22,738 | 22,824 | 22,934 | 23,007 | 23,007 | 23,007 | 23,007 | 23,007 |
| | Northwest | 35,916 | 34,875 | 34,928 | 34,826 | 34,717 | 34,630 | 34,631 | 34,622 | 34,645 |
| | Basin | 13,839 | 14,344 | 14,570 | 14,481 | 14,486 | 14,484 | 14,495 | 14,577 | 14,595 |
| | Rockies | 14,795 | 14,911 | 15,444 | 15,714 | 15,720 | 15,722 | 15,724 | 15,726 | 15,727 |
| | Desert SW | 35,465 | 35,988 | 36,389 | 36,225 | 36,111 | 36,212 | 36,196 | 36,231 | 36,284 |
| | No. CA | 31,581 | 32,098 | 32,649 | 33,083 | 33,144 | 33,206 | 33,266 | 33,248 | 33,295 |
| | So. CA/MX | 40,576 | 40,682 | 40,761 | 40,601 | 40,663 | 40,502 | 40,462 | 40,368 | 40,256 |
| | Total | 194,639 | 195,636 | 197,564 | 197,864 | 197,848 | 197,763 | 197,782 | 197,780 | 197,808 |
| Power Supply Margin | Canada | 1,965 | 1,790 | 1,458 | 1,177 | 890 | 436 | 43 | -284 | -777 |
| | Northwest | 8,406 | 7,064 | 6,747 | 6,301 | 5,882 | 5,423 | 5,050 | 4,649 | 4,185 |
| | Basin | 0 | 0 | -73 | -507 | -820 | -1,210 | -1,544 | -1,864 | -2,142 |
| | Rockies | 0 | -313 | -172 | -255 | -605 | -956 | -1,348 | -1,765 | -2,160 |
| | Desert SW | 0 | -626 | -1,366 | -2,618 | -3,733 | -4,707 | -5,764 | -6,832 | -7,799 |
| | No. CA | 0 | 0 | 0 | -111 | -601 | -1,098 | -1,573 | -2,152 | -2,693 |
| | So. CA/MX | 0 | -438 | -1,069 | -1,948 | -2,722 | -3,514 | -4,329 | -5,204 | -6,233 |
| | Total | 10,371 | 7,478 | 5,525 | 2,039 | -1,709 | -5,626 | -9,466 | -13,453 | -17,618 |

# Attachment 3: WECC Power Supply Assessment Policy

**DRAFT REVISION FOR APPROVAL**

**WESTERN ELECTRICITY COORDINATING COUNCIL**

## POWER SUPPLY ASSESSMENT POLICY

INTRODUCTION

The Western Electricity Coordinating Council was established to promote the reliable operation of the interconnected bulk power system by the coordination of planning and operation of generating and interconnected transmission facilities.

The Planning Coordination Committee (PCC) assigned the Loads and Resources Subcommittee (LRS) the task of developing an Adequacy of Supply Assessment Methodology. This document establishes the policy for conducting power supply assessments using the methodology developed by the LRS. This policy shall be periodically reviewed and revised as experience indicates.

PURPOSE OF POWER SUPPLY ASSESSMENT

To ensure the reliability of the interconnected bulk electric system, it is necessary to assess both the security and the adequacy of the overall Western Interconnection. This document is focused on the portion of the assessment dealing with the adequacy of power supply. As electric industry restructuring has altered the traditional model of the vertically integrated utility, the responsibility for maintaining the adequacy of the power supply is distributed among multiple private and public entities, in part relying on market mechanisms. Though there may not be specific entities entrusted to plan for adequate resources, there exists a need to assess whether projected resources will be sufficient to reliably meet demand. Such information will allow regulators and policy makers to anticipate potential shortfalls. Determinations can be made as to whether impediments or insufficient incentives exist in the market and whether utility integrated resource planning is bringing resources on line in a timely manner. Additionally, a high quality assessment can support efficient sharing of resources among sub-regions where feasible, and can inform transmission expansion planning efforts of the WECC Transmission Expansion Planning Policy Committee.

It is not the intent of an adequacy assessment to replace the market, create sanctionable criteria or anticipate future energy prices. Its purpose is to project whether enough physical resources exist, at any price, to meet load and possible reserves while considering the transmission transfer capabilities of major paths. Such an assessment will be consistent with NERC Standards.

It is recognized that it is impossible to provide 100% adequacy of power supply over all future circumstances. It is the purpose of this document to establish a uniform policy for assessing the adequacy of installed and identified future resources within the WECC region for the purposes of reporting within the Council, and to outside agencies. The assessments shall cover a period encompassing at least the next five years.

The Power Supply Assessment Methodology shall be developed and maintained by LRS. Adequacy of supply may be defined and measured in terms of generating reserve margins and transmission limitations between load and resource areas and/or based on probabilistic methods. Assessments shall consider both capacity and energy adequacy. Appropriate technical tools shall be developed and utilized in conducting the assessments. The assessments shall account for diversity of load and generation, and for transmission constraints between load and resource areas. To the extent that fuel supply interruptions are judged to be a valid and significant source of uncertainty this vulnerability should also be assessed.

CAPACITY ASSESSMENT METHODOLOGY AND RESOURCE ASSESSMENT GUIDELINES

As approved by the Board of Directors in July 2007, development of initial resource adequacy numerical guidelines for use in capacity (MW) assessments will use the Building Block approach. Components of the Building Block approach approved by the board include the following: provisions for contingency reserves, regulating reserves (both of which are required operating reserve components), additional forced outages to cover additional contingencies and temperature-induced load variations beyond expected peak loads. The method for determining a numerical value for sub-regions of WECC using these building blocks, and other influences on reliability, shall be determined by LRS with the concurrence of PCC.

DATA REQUIREMENTS

To aid WECC in assessing resource adequacy, the following general kinds of information shall be provided by WECC members:

Load Forecasts

- Electricity demand and energy forecasts, including uncertainties
  - Variations due to weather
  - Variations due to other factors affecting forecasts

Demand Side Management (DSM) Programs

- Existing and planned demand-side management programs
  - Direct controlled interruptible loads
  - Aggregate effects of multiple DSM programs

Resource Information

- Supply-side resource characteristics, including uncertainties
  - Consistent generator unit ratings, including seasonal variations and environmental considerations affecting hydro and thermal units
  - Availability of generating units
  - Fuel type
  - Fuel Supply risks

Transmission Information

- Capabilities, availability of transmission capacity, and other uncertainties

REPORTING OF POWER SUPPLY ADEQUACY

The assessment of generating reserve margins and transmission limitations between load and resource areas, accounting for uncertainties, shall be developed and the results reported on a seasonal basis. The assessment shall be consistent with the requirement for maintaining operating reserves as defined in the *WECC Minimum Operating Reliability Criteria* and NERC Operating Policies.

The results of this assessment should be packaged in a way to be useful to the WECC Board of Directors, regulatory and policy agencies of the states/provinces, and sub-regions that are interested in electricity reliability and adequacy throughout the footprint of the Western Interconnection. WECC should directly communicate the results to this community. In addition, WECC staff and LRS members should present the results to this community at meetings and other appropriate forums.

| | |
|---|---|
| Prepared by Load and Resources Subcommittee | September 2007 |
| Approved by Planning Coordination Committee | _____, 2007 |
| Approved by Board of Directors | _____,2007 |

# Attachment 4: 1-in-2 to 1-in-10 Calculation

EXAMPLE

| | Summer Temp | Winter HDD |
|---|---|---|
| 1990 | 91.0 | 71 |
| 1991 | 94.0 | 82 |
| 1992 | 97.0 | 49 |
| 1993 | 89.3 | 71 |
| 1994 | 95.5 | 72 |
| 1995 | 92.7 | 65 |
| 1996 | 92.0 | 85 |
| 1997 | 88.2 | 80 |
| 1998 | 93.0 | 75 |
| 1999 | 99.2 | 78 |
| 2000 | 91.5 | 36 |
| 2001 | 98.3 | 71 |
| 2002 | 102.8 | 37 |
| 2003 | 102.0 | 70 |
| 2004 | 95.2 | 82 |
| 2005 | 95.8 | 67 |
| 2006 | 95.2 | 72 |
| AVG | 94.9 | 68.5 |
| STD | 4.1 | 14.5 |

z = (x - xbar)/s
x = xbar + z*s

| | | |
|---|---|---|
| z = | 1.28 | 1.28 |
| Temp = | 100.121 | 86.991 |
| Pr() = | 0.900 | 0.900 |
| Temp Increase | 5.3 | 18.5 |
| MW/Degree | 7.030 | 3.386 |
| MW Increase | 37.0 | 62.8 |
| MW Load | 1,500 | 1,501 |
| % Increase | 2.5% | 4.2% |

# Attachment 5: Relationship of the Power Supply Assessment to Individual Load Serving Entities' Resource Adequacy Standards and Analyses

The values for reserve margins used in the PSA are not directly comparable to any values that might be used by individual LSEs or their regulators or local governing boards to evaluate their individual resource adequacy. Moreover, they are not intended to supplant any of those values. They are provided for the use of the WECC board and other users of the report to assess the overall state of the adequacy of the Western Interconnection.

The reserve margins in the PSA are not comparable to the values chosen by or applicable to an individual LSE for several reasons.

First, any given LSE may use different building blocks or different values for the building blocks, or even use an entirely different method to set its target reserve margin than what is used in the PSA. For instance an LSE may include the effect of 1-in-20 weather in its margin, rather than the 1-in-10 weather used in the PSA. It may include a factor to account for delays in expected future plant construction, a concern that is addressed in a different way in the PSA.

Second, the data are collected and analyzed by balancing authority. There are 35 balancing authority areas in WECC. In many cases the balancing authority boundaries are the same as those of the LSEs, but in several significant instances, they are not. For example, the CAISO balancing authority area contains three very large LSEs, PG&E, SCE and SDG&E. Each of which may want to set their own resource adequacy reserve margins, subject to the regulation of the CPUC.

California also has 13 electricity service providers (ESPs) with no fixed customer service requirements and no obligation to plan loads and resources beyond those established by CPUC and CAISO year-ahead resource adequacy requirements. Finally, there are about 25 additional publicly-owned utilities that encompass traditional utilities and joint power authorities operating much like an ESP. This amalgam of LSEs exists in conjunction with a generating industry that is partially merchant-owned and partially LSE-owned. Under these circumstances the CAISO has a more difficult job to project aggregate loads and to describe resource additions accurately than does an integrated utility also operating as a balancing authority.

As an example of this effect, this balancing authority exhibits substantial load diversity that is moderated when looking at the balancing authority's loads as a whole. This affects the building block component for 1-in-10 weather stresses. For example, the California Bay area by itself would exhibit about a 7 percent weather adder for such a weather stress, but in the context of larger areas we see smaller adders, up to the overall CAISO balancing authority area where we see an adder for the overall load that is lower than this. The PSA has included separate weather analyses of the three LSEs in the CAISO footprint.

Third, the "bubbles" which are the basic units for the analysis of the PSA, which employs a model called SAM, are in a number of cases made up of several balancing authorities. Some bubbles are identical to an individual balancing authority, some generator-only entities, and in one case, a bubble contains only a part of a balancing authority. For Example, the BC bubble is only the BCTC area, the Four Corners bubble is generation only, the Arizona bubble is three balancing authorities (APS, SRP and TEP), and the Northern California bubble consists of only a piece of the CAISO but more than one LSE. There are 26 bubbles in SAM.

Fourth, the margins developed at the balancing authority level are averaged across seven sub-areas that are larger (in some cases, substantially larger) than individual balancing authority areas. The sub-area averages are used for each of the bubbles in the sub-area. The sub-areas used in the PSA are shown in Table 1 below, as well as the SAM bubbles that make up each sub-area and the resulting values for winter and summer.

Table 1

| Sub-Area | SAM Zones Included in Sub-Area | Summer Margin | Winter Margin |
|---|---|---|---|
| Canada | British Columbia, Alberta | 12.0% | 12.8% |
| Northwest | Pacific Northwest, COB, Montana | 13.7% | 16.3% |
| Basin | Idaho, Northern Nevada, Utah, IPP | 12.8% | 13.5% |
| Rockies | Colorado East, Colorado West, Wyoming | 14.2% | 15.4% |
| Desert Southwest | Arizona, New Mexico, Southern Nevada, IID, Four Corners, Palo Verde | 15.7% | 14.6% |
| Northern California | Northern California, Central California San Francisco, SMUD | 16.5% | 12.5% |
| Southern California/Mexico | Southern California, San Diego, LADWP, Comision Federal de Electricidad (CFE) | 16.6% | 13.0% |
| WECC Total | | 15.0% | 14.1% |

The sequence described above is done for several reasons, having to do primarily with constraints on the data and on the analytic method itself.

The primary data constraint is that we do not ask for, and cannot take account of, any contractual obligations between LSEs that might shift resources from one LSE or bubble to another. The PSA only accounts for the ownership splits of some jointly owned plants, those whose output is divided among LSEs that are incorporated into different bubbles. The PSA is a physical load and resource analysis and is not designed to evaluate the ability of any individual LSE to meet its load in the future.

The analytical limitation has to do with how SAM simulates economy transactions among bubbles, after individual bubble loads are met by resources in the bubble, subject to transmission limitations among the bubbles. The process for meeting deficit-bubble needs by surplus-bubble resources is governed by the internal algorithm of SAM, which essentially meets the needs of the closest bubble first. There are not economic or contractual drivers to this process.

Both of these considerations, as well as the aggregation of LSEs into bubbles, substantially limit the applicability of the analysis to individual LSEs, so as to make any attempt to derive individual LSE information from the analysis of very limited value. The level at which the analysis is meaningful and informative is the sub-area level for which the results are reported.

# Attachment 6: Energy Assessment – Pacific Northwest

In an ongoing effort to improve WECC's Power Supply Assessment, the Bonneville Power Administration (BPA) and the Northwest Power and Conservation Council (NWPCC) have again prepared an energy assessment[10] for the Pacific Northwest (PNW), which was vetted with representatives of public and investor-owned utilities, state regulatory and energy offices and other Northwest energy stakeholders at the June 20, 2007 PNW Resource Adequacy Forum Technical Committee meeting and at the June 27, 2007 Forum Steering Committee meeting.

Since the PNW (defined in the 1980 Power Act as the U.S. Columbia River drainage including Washington, Oregon, Idaho, part of Montana and small parts of several other states) is energy- rather than capacity-constrained, BPA and the NWPCC undertook the task to develop an energy assessment described in this Attachment.

Figure 1 depicts the annual energy load/resource balances under four scenarios:

- Critical hydro (1937 water year)
- Adverse hydro using the 85$^{th}$ percentile water condition (1973 water year)
- Average water (1929-78 water years), and
- The adequacy standard recommended by the RA Forum and adopted by the NWPCC in May of 2006

The load/resource balance includes projected loads, existing generation and demand-side management resources, and future committed resources for the Pacific Northwest as well as firm imports and exports. It also includes PNW regional market resources, that is, independent power producer (IPP) generators not under contract to load-serving entities. Critical hydro generation is based on historical stream flows from September of 1936 through August of 1937.

The load/resource balance calculated for the PNW adequacy standard includes contributions from "non-firm" resources. Non-firm resources include seasonal out-of-region market purchases, primarily from California, and additional hydro energy derived from the flexibility of the hydroelectric system. The value assigned to non-firm resources is characterized as a "planning adjustment" and is set via a loss-of-load-probability analysis, currently assessed at 1,500 average megawatts.[11] It is interesting to note that the annual load/resource balances calculated for the adequacy standard are nearly equivalent to the balances calculated using the 85$^{th}$ percentile (85 percent exceedence) adverse water condition (see Figure 1).

The tables at the end of this attachment show monthly load/resource balances for the time frame 2007 through 2015. In this assessment, resources have not been dispatched to meet load. Instead, it is a tally of available resources to meet load. The tables show energy deficits

[10] The assessment is a joint BPA-Council energy load/resource balance based on the 2006 BPA White Book, the Council's Fifth Power Plan and recent informational updates.

[11] The BPA dictionary defines an average megawatt as "the unit of energy output over a year, equivalent to the energy produced by the continuous operation of one megawatt of capacity over that period of time."

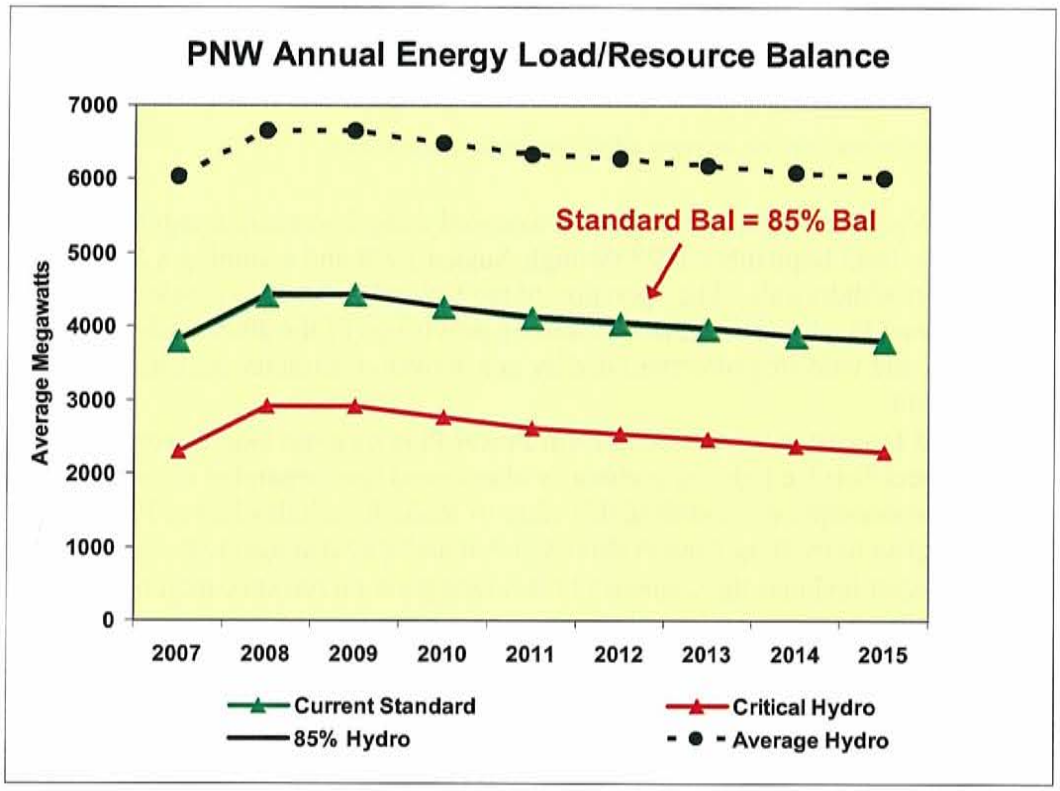
in winter months because the monthly assessment does not show a realistic estimate for market purchases from California, or other sources outside the PNW. The planning adjustment, which includes out-of-region market purchases, is computed only as an annual average value. Perhaps future refinements to the PNW assessment will include monthly estimates for the planning adjustment.

Other key assumptions for the energy adequacy assessment are:

- Pacific Northwest hydro generation is assessed using historical unregulated stream flow data from September 1928 through August 1978 and assuming a 1990 level of irrigation withdrawals. The operation of the Columbia River hydroelectric system is constrained by physical limitations and by provisions of the 2004 Biological Opinion (for fish and wildlife protection) and by non-power constraints, such as recreation and navigation.
- The load forecast is the Council's Fifth Power Plan medium load forecast for the PNW, with Direct Service Industry (primarily aluminum) load separated out to explicitly show the assumptions regarding this class of load. It includes Power Plan assumptions with respect to existing conservation and demand-side management.
- The forecast includes the Council's best information on resource maintenance outages. The assessment includes forced outages as a constant derate for each resource across all of the months of the year, based on historical experience. The loss-of-load-probability assessment, which sets the value of the planning adjustment, models forced outages as a random variable.
- The resource information includes all existing and committed generation facilities (including those of independent power producers, whose contractual commitments to the PNW and out-of-area entities are unknown) as well as firm contracts based on BPA's 2006 White Book.
- PNW transmission constraints are not modeled (with very limited exceptions) in this assessment and this may result in an overestimate of generation deliverable to load. It is not assumed to be very significant.

CAVEAT: Note that there are a number of important differences between this analysis and that in the rest of the PSA: the definition of "committed" resources used in the PNW for this analysis is different, the load forecast is not the same as that used in the PSA and the analytical model is different from that used in the PSA. Moreover, the analysis for the PNW standard includes the ability to purchase from other sub-regions (primarily California) under different assumptions than those used in the SAM analysis for the PSA.

Figure 1




This graph shows the impact of the wide variation in Pacific Northwest hydro conditions on the calculated adequacy of the system.

## 2007 Energy Load/Resource Balance
## (MWa)

### Pacific Northwest Regional Resource Adequacy Assessment

**Energy Load/Resource Balance Assessment** **2007 Bal = 3806** **Target = 0**

**NWPCC**

**June 19, 2007** **Last Update**

| Summary | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Net Demand | 19544 | 19537 | 21352 | 22752 | 23386 | 22430 | 21005 | 19695 | 19259 | 19921 | 20684 | 20466 | **20831** |
| Net Resources | 22733 | 23250 | 27205 | 27576 | 25349 | 24659 | 23609 | 22236 | 22766 | 25238 | 26238 | 24746 | **24636** |
| **L/R Balance** | **3188** | **3713** | **5853** | **4823** | **1963** | **2229** | **2603** | **2541** | **3508** | **5317** | **5554** | **4279** | **3806** |
| W/O Plan Adjustment | 1688 | 2213 | 4353 | 3323 | 463 | 729 | 1103 | 1041 | 2008 | 3817 | 4054 | 2779 | **2306** |
| W/O Uncontracted | 688 | 1213 | 975 | -88 | -2951 | -2660 | -1798 | -1381 | -383 | 2817 | 3054 | 1779 | **121** |

| Demand | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Non-DSI | 18600 | 19210 | 21402 | 23002 | 23479 | 22435 | 20813 | 19309 | 18779 | 19393 | 20137 | 19806 | **20524** |
| DSI | 302 | 315 | 316 | 316 | 296 | 297 | 297 | 298 | 295 | 294 | 297 | 295 | **302** |
| Coulee Pumping | 137 | 65 | 2 | 2 | 2 | 2 | 28 | 158 | 238 | 255 | 274 | 238 | **117** |
| **Total** | **19039** | **19590** | **21720** | **23320** | **23777** | **22734** | **21137** | **19764** | **19313** | **19942** | **20707** | **20339** | **20943** |

| Resources | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Critical Hydro | 10409 | 10970 | 12398 | 12610 | 10331 | 9795 | 10533 | 10913 | 11447 | 15131 | 13467 | 11953 | **11672** |
| Non-Hydro Firm | 9824 | 9780 | 9929 | 10054 | 10104 | 9974 | 8675 | 7401 | 7428 | 7607 | 10271 | 10293 | **9279** |
| PNW Uncontracted | 1000 | 1000 | 3378 | 3412 | 3414 | 3389 | 2901 | 2422 | 2391 | 1000 | 1000 | 1000 | **2185** |
| Planning Adjustment | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | **1500** |

| Firm Contracts | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Exports | 1479 | 912 | 862 | 875 | 873 | 870 | 860 | 870 | 794 | 1031 | 1116 | 1148 | **974** |
| Imports | 974 | 965 | 1230 | 1443 | 1264 | 1174 | 992 | 939 | 848 | 1052 | 1139 | 1021 | **1086** |

## 2008 Energy Load/Resource Balance
## (MWa)

### Pacific Northwest Regional Resource Adequacy Assessment

**Energy Load/Resource Balance Assessment** **2008 Bal = 4421** **Target = 0**

**NWPCC**

**June 19, 2007** **Last Update**

| Summary | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Net Demand | 19373 | 19636 | 21275 | 22909 | 23532 | 22506 | 21001 | 19830 | 19274 | 19964 | 20710 | 20325 | **20856** |
| Net Resources | 23185 | 23711 | 27974 | 28434 | 26210 | 25503 | 24380 | 23366 | 23894 | 25394 | 26400 | 24858 | **25277** |
| **L/R Balance** | **3812** | **4074** | **6699** | **5524** | **2678** | **2997** | **3378** | **3535** | **4620** | **5430** | **5690** | **4532** | **4421** |
| W/O Plan Adjustment | 2312 | 2574 | 5199 | 4024 | 1178 | 1497 | 1878 | 2035 | 3120 | 3930 | 4190 | 3032 | **2921** |
| W/O Uncontracted | 1312 | 1574 | 1523 | 310 | -2539 | -2193 | -1284 | -1062 | 66 | 2930 | 3190 | 2032 | **503** |
| | | | | | | | | | | | | | |
| **Demand** | **Sep** | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Ann** |
| Non-DSI | 18671 | 19300 | 21303 | 23166 | 23634 | 22571 | 20870 | 19494 | 18871 | 19547 | 20363 | 19829 | **20629** |
| DSI | 302 | 315 | 316 | 316 | 296 | 297 | 297 | 298 | 295 | 294 | 297 | 295 | **302** |
| Coulee Pumping | 137 | 65 | 2 | 2 | 2 | 2 | 28 | 158 | 238 | 255 | 274 | 238 | **117** |
| **Total** | **19110** | **19680** | **21621** | **23484** | **23932** | **22870** | **21195** | **19950** | **19404** | **20096** | **20934** | **20362** | **21048** |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| **Resources** | **Sep** | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Ann** |
| Critical Hydro | 10409 | 10970 | 12398 | 12610 | 10331 | 9795 | 10533 | 10913 | 11447 | 15131 | 13467 | 11953 | **11672** |
| Non-Hydro Firm | 10276 | 10241 | 10400 | 10609 | 10662 | 10519 | 9184 | 7856 | 7892 | 7764 | 10433 | 10405 | **9687** |
| PNW Uncontracted | 1000 | 1000 | 3676 | 3714 | 3717 | 3689 | 3162 | 3097 | 3054 | 1000 | 1000 | 1000 | **2418** |
| Planning Adjustment | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | **1500** |

## 2009 Energy Load/Resource Balance
## (MWa)

### Pacific Northwest Regional Resource Adequacy Assessment

**Energy Load/Resource Balance Assessment** **2009 Bal = 4428** **Target = 0**

**NWPCC**

**June 19, 2007** **Last Update**

| Summary | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Net Demand | 19311 | 19814 | 21450 | 23309 | 23835 | 22868 | 21350 | 20098 | 19439 | 20361 | 20955 | 20645 | **21114** |
| Net Resources | 23271 | 23774 | 28654 | 29050 | 26828 | 26115 | 24912 | 23366 | 23894 | 25394 | 26400 | 24858 | **25542** |
| **L/R Balance** | **3960** | **3959** | **7204** | **5741** | **2993** | **3247** | **3561** | **3267** | **4455** | **5033** | **5445** | **4212** | **4428** |
| W/O Plan Adjustment | 2460 | 2459 | 5704 | 4241 | 1493 | 1747 | 2061 | 1767 | 2955 | 3533 | 3945 | 2712 | **2928** |
| W/O Uncontracted | 1460 | 1459 | 1419 | -90 | -2842 | -2554 | -1633 | -1329 | -100 | 2533 | 2945 | 1712 | **263** |

| Demand | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Non-DSI | 18928 | 19451 | 21372 | 23411 | 23722 | 22729 | 21111 | 19657 | 18950 | 19739 | 20479 | 19972 | **20787** |
| DSI | 303 | 315 | 316 | 315 | 296 | 297 | 297 | 298 | 295 | 294 | 297 | 295 | **302** |
| Coulee Pumping | 137 | 65 | 2 | 2 | 2 | 2 | 28 | 158 | 238 | 255 | 274 | 238 | **117** |
| **Total** | **19368** | **19831** | **21690** | **23728** | **24020** | **23028** | **21436** | **20113** | **19483** | **20288** | **21050** | **20505** | **21206** |

| Resources | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Critical Hydro | 10409 | 10970 | 12398 | 12610 | 10331 | 9795 | 10533 | 10913 | 11447 | 15131 | 13467 | 11953 | **11672** |
| Non-Hydro Firm | 10363 | 10303 | 10471 | 10609 | 10662 | 10519 | 9184 | 7856 | 7892 | 7764 | 10433 | 10405 | **9705** |
| PNW Uncontracted | 1000 | 1000 | 4285 | 4331 | 4335 | 4301 | 3694 | 3097 | 3054 | 1000 | 1000 | 1000 | **2665** |
| Planning Adjustment | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | **1500** |

| Firm Contracts | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Exports | 908 | 826 | 777 | 787 | 784 | 783 | 776 | 791 | 709 | 890 | 893 | 983 | **826** |
| Imports | 965 | 843 | 1017 | 1206 | 969 | 943 | 862 | 806 | 753 | 817 | 988 | 843 | **918** |

## 2010 Energy Load/Resource Balance
## (MWa)

### Pacific Northwest Regional Resource Adequacy Assessment

**Energy Load/Resource Balance Assessment** **2010 Bal = 4261** **Target = 0**

**NWPCC**

**June 19, 2007** **Last Update**

| Summary | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Net Demand | 19727 | 20046 | 21839 | 23732 | 24016 | 23093 | 21618 | 20322 | 19660 | 20545 | 21172 | 20832 | **21378** |
| Net Resources | 23515 | 24025 | 28654 | 29050 | 26828 | 26115 | 24912 | 23366 | 23894 | 25576 | 26637 | 25095 | **25639** |
| **L/R Balance** | **3788** | **3979** | **6815** | **5318** | **2812** | **3023** | **3294** | **3043** | **4234** | **5031** | **5465** | **4263** | **4261** |
| W/O Plan Adjustment | 2288 | 2479 | 5315 | 3818 | 1312 | 1523 | 1794 | 1543 | 2734 | 3531 | 3965 | 2763 | **2761** |
| W/O Uncontracted | 1288 | 1479 | 1289 | -249 | -2759 | -2518 | -1676 | -1364 | -134 | 2531 | 2965 | 1763 | **233** |

| Demand | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Non-DSI | 19076 | 19527 | 21538 | 23547 | 23810 | 22860 | 21285 | 19786 | 19078 | 19877 | 20558 | 20165 | **20919** |
| DSI | 303 | 315 | 316 | 316 | 296 | 297 | 297 | 298 | 295 | 294 | 297 | 295 | **302** |
| Coulee Pumping | 137 | 65 | 2 | 2 | 2 | 2 | 28 | 158 | 238 | 255 | 274 | 238 | **117** |
| **Total** | **19516** | **19907** | **21856** | **23865** | **24108** | **23159** | **21610** | **20242** | **19611** | **20426** | **21129** | **20698** | **21338** |

| Resources | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Critical Hydro | 10409 | 10970 | 12398 | 12610 | 10331 | 9795 | 10533 | 10913 | 11447 | 15131 | 13467 | 11953 | **11672** |
| Non-Hydro Firm | 10606 | 10555 | 10730 | 10873 | 10926 | 10779 | 9409 | 8046 | 8078 | 7946 | 10670 | 10642 | **9938** |
| PNW Uncontracted | 1000 | 1000 | 4026 | 4067 | 4070 | 4041 | 3469 | 2907 | 2869 | 1000 | 1000 | 1000 | **2528** |
| Planning Adjustment | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | **1500** |

| Firm Contracts | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Exports | 985 | 924 | 875 | 884 | 881 | 881 | 875 | 890 | 809 | 982 | 983 | 934 | **909** |
| Imports | 774 | 785 | 892 | 1017 | 973 | 947 | 867 | 810 | 760 | 863 | 940 | 800 | **869** |

## 2011 Energy Load/Resource Balance
## (MWa)

### Pacific Northwest Regional Resource Adequacy Assessment

**Energy Load/Resource Balance Assessment** **2011 Bal = 4114** **Target = 0**

**NWPCC**

**June 19, 2007** **Last Update**

| Summary | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Net Demand | 19795 | 20068 | 21972 | 23793 | 24256 | 23276 | 21808 | 20445 | 19888 | 20710 | 21277 | 21085 | **21525** |
| Net Resources | 23515 | 24025 | 28654 | 29050 | 26828 | 26115 | 24912 | 23366 | 23894 | 25576 | 26637 | 25095 | **25639** |
| **L/R Balance** | **3720** | **3958** | **6681** | **5257** | **2571** | **2840** | **3104** | **2921** | **4006** | **4867** | **5360** | **4010** | **4114** |
| W/O Plan Adjustment | 2220 | 2458 | 5181 | 3757 | 1071 | 1340 | 1604 | 1421 | 2506 | 3367 | 3860 | 2510 | **2614** |
| W/O Uncontracted | 1220 | 1458 | 1155 | -310 | -2999 | -2701 | -1866 | -1486 | -362 | 2367 | 2860 | 1510 | **85** |

| Demand | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Non-DSI | 19201 | 19600 | 21722 | 23657 | 23989 | 22983 | 21416 | 19858 | 19258 | 19995 | 20612 | 20341 | **21046** |
| DSI | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | **297** |
| Coulee Pumping | 137 | 65 | 2 | 2 | 2 | 2 | 28 | 158 | 238 | 255 | 274 | 238 | **117** |
| **Total** | **19635** | **19962** | **22021** | **23956** | **24288** | **23282** | **21741** | **20313** | **19793** | **20547** | **21183** | **20876** | **21461** |

| Resources | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Critical Hydro | 10409 | 10970 | 12398 | 12610 | 10331 | 9795 | 10533 | 10913 | 11447 | 15131 | 13467 | 11953 | **11672** |
| Non-Hydro Firm | 10606 | 10555 | 10730 | 10873 | 10926 | 10779 | 9409 | 8046 | 8078 | 7946 | 10670 | 10642 | **9938** |
| PNW Uncontracted | 1000 | 1000 | 4026 | 4067 | 4070 | 4041 | 3469 | 2907 | 2869 | 1000 | 1000 | 1000 | **2528** |
| Planning Adjustment | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | **1500** |

| Firm Contracts | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Exports | 935 | 883 | 839 | 849 | 846 | 845 | 838 | 852 | 769 | 948 | 950 | 932 | **874** |
| Imports | 775 | 777 | 888 | 1012 | 878 | 851 | 771 | 720 | 674 | 785 | 856 | 723 | **809** |

## 2012 Energy Load/Resource Balance
## (MWa)

### Pacific Northwest Regional Resource Adequacy Assessment

**Energy Load/Resource Balance Assessment** **2012 Bal = 4046** **Target = 0**

**NWPCC**

**June 19, 2007** **Last Update**

| Summary | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Net Demand | 19983 | 20205 | 22110 | 23877 | 24290 | 23296 | 21745 | 20457 | 20007 | 20720 | 21375 | 21110 | **21593** |
| Net Resources | 23515 | 24025 | 28654 | 29050 | 26828 | 26115 | 24912 | 23366 | 23894 | 25576 | 26637 | 25095 | **25639** |
| **L/R Balance** | **3532** | **3820** | **6544** | **5173** | **2538** | **2819** | **3167** | **2908** | **3887** | **4856** | **5262** | **3985** | **4046** |
| W/O Plan Adjustment | 2032 | 2320 | 5044 | 3673 | 1038 | 1319 | 1667 | 1408 | 2387 | 3356 | 3762 | 2485 | **2546** |
| W/O Uncontracted | 1032 | 1320 | 1018 | -394 | -3033 | -2722 | -1803 | -1498 | -481 | 2356 | 2762 | 1485 | **18** |

| Demand | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Non-DSI | 19312 | 19716 | 21842 | 23732 | 24103 | 23087 | 21430 | 19934 | 19435 | 20063 | 20787 | 20440 | **21151** |
| DSI | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | **297** |
| Coulee Pumping | 137 | 65 | 2 | 2 | 2 | 2 | 28 | 158 | 238 | 255 | 274 | 238 | **117** |
| **Total** | **19746** | **20078** | **22141** | **24031** | **24402** | **23386** | **21755** | **20389** | **19970** | **20615** | **21358** | **20975** | **21565** |

| Resources | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Critical Hydro | 10409 | 10970 | 12398 | 12610 | 10331 | 9795 | 10533 | 10913 | 11447 | 15131 | 13467 | 11953 | **11672** |
| Non-Hydro Firm | 10606 | 10555 | 10730 | 10873 | 10926 | 10779 | 9409 | 8046 | 8078 | 7946 | 10670 | 10642 | **9938** |
| PNW Uncontracted | 1000 | 1000 | 4026 | 4067 | 4070 | 4041 | 3469 | 2907 | 2869 | 1000 | 1000 | 1000 | **2528** |
| Planning Adjustment | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | **1500** |

| Firm Contracts | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Exports | 931 | 824 | 774 | 775 | 774 | 774 | 773 | 798 | 717 | 886 | 881 | 863 | **814** |
| Imports | 694 | 697 | 805 | 929 | 886 | 864 | 783 | 730 | 680 | 781 | 864 | 728 | **786** |

## 2013 Energy Load/Resource Balance
## (MWa)

### Pacific Northwest Regional Resource Adequacy Assessment

**Energy Load/Resource Balance Assessment** **2013 Bal = 3967** **Target = 0**

**NWPCC**

**June 19, 2007** **Last Update**

| Summary | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Net Demand | 19914 | 20401 | 22195 | 23922 | 24421 | 23393 | 21817 | 20623 | 20067 | 20722 | 21504 | 21149 | **21672** |
| Net Resources | 23515 | 24025 | 28654 | 29050 | 26828 | 26115 | 24912 | 23366 | 23894 | 25576 | 26637 | 25095 | **25639** |
| **L/R Balance** | **3601** | **3625** | **6459** | **5128** | **2406** | **2722** | **3095** | **2743** | **3827** | **4854** | **5133** | **3946** | **3967** |
| W/O Plan Adjustment | 2101 | 2125 | 4959 | 3628 | 906 | 1222 | 1595 | 1243 | 2327 | 3354 | 3633 | 2446 | **2467** |
| W/O Uncontracted | 1101 | 1125 | 933 | -439 | -3164 | -2819 | -1874 | -1664 | -542 | 2354 | 2633 | 1446 | **-62** |

| Demand | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Non-DSI | 19312 | 19946 | 21949 | 23804 | 24260 | 23212 | 21541 | 20137 | 19534 | 20105 | 20955 | 20516 | **21266** |
| DSI | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | **297** |
| Coulee Pumping | 137 | 65 | 2 | 2 | 2 | 2 | 28 | 158 | 238 | 255 | 274 | 238 | **117** |
| **Total** | **19746** | **20308** | **22248** | **24103** | **24559** | **23511** | **21866** | **20592** | **20069** | **20657** | **21526** | **21051** | **21681** |

| Resources | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Critical Hydro | 10409 | 10970 | 12398 | 12610 | 10331 | 9795 | 10533 | 10913 | 11447 | 15131 | 13467 | 11953 | **11672** |
| Non-Hydro Firm | 10606 | 10555 | 10730 | 10873 | 10926 | 10779 | 9409 | 8046 | 8078 | 7946 | 10670 | 10642 | **9938** |
| PNW Uncontracted | 1000 | 1000 | 4026 | 4067 | 4070 | 4041 | 3469 | 2907 | 2869 | 1000 | 1000 | 1000 | **2528** |
| Planning Adjustment | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | **1500** |

| Firm Contracts | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Exports | 864 | 794 | 742 | 743 | 742 | 742 | 741 | 766 | 685 | 853 | 850 | 832 | **780** |
| Imports | 696 | 701 | 795 | 924 | 880 | 860 | 790 | 735 | 687 | 788 | 872 | 734 | **788** |

## 2014 Energy Load/Resource Balance
## (MWa)

### Pacific Northwest Regional Resource Adequacy Assessment

**Energy Load/Resource Balance Assessment** **2014 Bal = 3868** **Target = 0**

**NWPCC**

**June 19, 2007** **Last Update**

| Summary | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Net Demand | 20044 | 20505 | 22237 | 24075 | 24508 | 23496 | 21921 | 20730 | 20122 | 20866 | 21620 | 21186 | **21770** |
| Net Resources | 23515 | 24025 | 28654 | 29050 | 26828 | 26115 | 24912 | 23366 | 23894 | 25576 | 26637 | 25095 | **25639** |
| **L/R Balance** | **3471** | **3520** | **6417** | **4975** | **2320** | **2619** | **2991** | **2636** | **3772** | **4710** | **5017** | **3909** | **3868** |
| W/O Plan Adjustment | 1971 | 2020 | 4917 | 3475 | 820 | 1119 | 1491 | 1136 | 2272 | 3210 | 3517 | 2409 | **2368** |
| W/O Uncontracted | 971 | 1020 | 890 | -592 | -3251 | -2922 | -1978 | -1771 | -596 | 2210 | 2517 | 1409 | **-160** |

| Demand | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Non-DSI | 19478 | 20065 | 22006 | 23973 | 24363 | 23331 | 21661 | 20259 | 19606 | 20266 | 21089 | 20572 | **21383** |
| DSI | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | **297** |
| Coulee Pumping | 137 | 65 | 2 | 2 | 2 | 2 | 28 | 158 | 238 | 255 | 274 | 238 | **117** |
| **Total** | **19912** | **20427** | **22305** | **24272** | **24662** | **23630** | **21986** | **20714** | **20141** | **20818** | **21660** | **21107** | **21797** |

| Resources | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Critical Hydro | 10409 | 10970 | 12398 | 12610 | 10331 | 9795 | 10533 | 10913 | 11447 | 15131 | 13467 | 11953 | **11672** |
| Non-Hydro Firm | 10606 | 10555 | 10730 | 10873 | 10926 | 10779 | 9409 | 8046 | 8078 | 7946 | 10670 | 10642 | **9938** |
| PNW Uncontracted | 1000 | 1000 | 4026 | 4067 | 4070 | 4041 | 3469 | 2907 | 2869 | 1000 | 1000 | 1000 | **2528** |
| Planning Adjustment | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | **1500** |

| Firm Contracts | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Exports | 834 | 784 | 732 | 733 | 732 | 732 | 731 | 756 | 674 | 843 | 840 | 819 | **768** |
| Imports | 702 | 706 | 800 | 930 | 886 | 866 | 796 | 740 | 693 | 795 | 880 | 740 | **794** |

## 2015 Energy Load/Resource Balance
## (MWa)

### Pacific Northwest Regional Resource Adequacy Assessment

**Energy Load/Resource Balance Assessment** **2015 Bal = 3796** **Target = 0**

**NWPCC**

**June 19, 2007** **Last Update**

| Summary | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Net Demand | 20211 | 20584 | 22294 | 24215 | 24523 | 23550 | 22028 | 20780 | 20113 | 20987 | 21659 | 21234 | **21843** |
| Net Resources | 23515 | 24025 | 28654 | 29050 | 26828 | 26115 | 24912 | 23366 | 23894 | 25576 | 26637 | 25095 | **25639** |
| **L/R Balance** | **3304** | **3441** | **6360** | **4835** | **2304** | **2565** | **2883** | **2586** | **3781** | **4590** | **4978** | **3861** | **3796** |
| W/O Plan Adjustment | 1804 | 1941 | 4860 | 3335 | 804 | 1065 | 1383 | 1086 | 2281 | 3090 | 3478 | 2361 | **2296** |
| W/O Uncontracted | 804 | 941 | 834 | -732 | -3266 | -2976 | -2086 | -1821 | -588 | 2090 | 2478 | 1361 | **-232** |

| Demand | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Non-DSI | 19664 | 20162 | 22082 | 24129 | 24436 | 23444 | 21826 | 20367 | 19660 | 20449 | 21187 | 20680 | **21501** |
| DSI | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | 297 | **297** |
| Coulee Pumping | 137 | 65 | 2 | 2 | 2 | 2 | 28 | 158 | 238 | 255 | 274 | 238 | **117** |
| **Total** | **20098** | **20524** | **22381** | **24428** | **24735** | **23743** | **22151** | **20822** | **20195** | **21001** | **21758** | **21215** | **21915** |

| Resources | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Critical Hydro | 10409 | 10970 | 12398 | 12610 | 10331 | 9795 | 10533 | 10913 | 11447 | 15131 | 13467 | 11953 | **11672** |
| Non-Hydro Firm | 10606 | 10555 | 10730 | 10873 | 10926 | 10779 | 9409 | 8046 | 8078 | 7946 | 10670 | 10642 | **9938** |
| PNW Uncontracted | 1000 | 1000 | 4026 | 4067 | 4070 | 4041 | 3469 | 2907 | 2869 | 1000 | 1000 | 1000 | **2528** |
| Planning Adjustment | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | 1500 | **1500** |

| Firm Contracts | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Ann |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Exports | 823 | 772 | 720 | 721 | 680 | 680 | 679 | 704 | 619 | 789 | 784 | 762 | **728** |
| Imports | 710 | 712 | 807 | 934 | 892 | 873 | 802 | 746 | 701 | 803 | 883 | 743 | **800** |

# Attachment 7: Generation Additions/Retirements

Note that wind derates for effective capacity factor are aggregated at the end of each annual table.

**Class 1 Additions**

| Area | Balancing Authority | Name | Unit Type | Net Capability MW Summer | Net Capability MW Winter | Fuel Type | Commercial Operation Dates Original | Commercial Operation Dates New | Status |
|---|---|---|---|---|---|---|---|---|---|
| NWCA | AESO | Kettles Hill | WT | 14 | 14 | WND | 2001 | 2007 | U |
| NWCA | AESO | Kettles Hill | WT | 13 | 13 | WND | 2001 | 2007 | U |
| NWCA | AESO | Kettles Hill | WT | 5 | 5 | WND | 2001 | 2007 | U |
| NWCA | AESO | Kettles Hill | WT | 5 | 5 | WND | 2001 | 2007 | U |
| NWCA | AESO | Kettles Hill | WT | 16 | 16 | WND | 2001 | 2007 | U |
| NWCA | AESO | Horizon Upgrading | GT | 86 | 86 | NG | 2007 | 2007 | U |
| NWCA | AESO | Horizon Upgrading | GT | 86 | 86 | NG | 2007 | 2007 | U |
| NWCA | AESO | Horizon Upgrading | ST | 15 | 15 | NG | 2007 | 2007 | U |
| NWUW | BPA | Biglow Canyon | WT | 126 | 126 | WND | 2006 | 2007 | U |
| NWUW | BPA | Klondike Phase 3 | WT | 221 | 221 | WND | 2007 | 2007 | U |
| SCE | CISO | SCE Barre | GT | 49 | 49 | NG | 2007 | 2007 | U |
| SCE | CISO | SCE Center | GT | 49 | 49 | NG | 2007 | 2007 | U |
| SCE | CISO | SCE Etiwanda | GT | 49 | 49 | NG | 2007 | 2007 | U |
| SCE | CISO | SCE Mira Loma | GT | 49 | 49 | NG | 2007 | 2007 | U |
| PGES | CISO | Ox Mountain | BM | 11 | 11 | LFG | 2007 | 2007 | U |
| SCE | CISO | SCE Mandalay | GT | 49 | 49 | NG | 2007 | 2007 | U |
| PGES | CISO | Chowchilla | BM | 13 | 13 | WDS | 2007 | 2007 | U |
| PGEN | CISO | El Nido | BM | 13 | 13 | WDS | 2007 | 2007 | U |
| SCE | CISO | Chiquita Canyon | BM | 9 | 9 | LFG | 2007 | 2007 | U |
| ID | IPC | Emmett Facility | BM | 7 | 7 | WDS | 2006 | 2007 | U |
| COE | PSCO | Logan County | WT | 200 | 200 | WND | 2007 | 2007 | U |
| COE | PSCO | Peetz Table | WT | 200 | 200 | WND | 2007 | 2007 | U |
| COE | PSCO | Twin Buttes Cedar Ck | WT | 300 | 300 | WND | 2007 | 2007 | U |
| NVN | SPP | TS Power | GT | 0 | 0 | DFO | 2007 | 2007 | U |
| NVN | SPP | TS Power | GT | 0 | 0 | DFO | 2007 | 2007 | U |
| NVN | SPP | TS Power | GT | 0 | 0 | DFO | 2007 | 2007 | U |
| NVN | SPP | TS Power | GT | 0 | 0 | DFO | 2007 | 2007 | U |
| WY | WACM | WYGEN | ST | 80 | 80 | BIT | 2007 | 2007 | U |
| NWCB | BC Hydro | Brilliant Exp | HY | 120 | 120 | WAT | 2006 | 2007 | V |
| NWUW | BPA | Mint Farm | CT | 219 | 219 | NG | 2002 | 2007 | V |
| NWUW | BPA | Mint Farm | CA | 157 | 157 | NG | 2002 | 2007 | V |
| PGEN | CISO | Bottle Rock | GE | 55 | 55 | GEO | 2007 | 2007 | V |
| PGEN | CISO | Fresno CG Exp. | ST | 73 | 73 | NG | 2007 | 2007 | V |
| SCE | CISO | Inland Empire | CC | 790 | 790 | NG | 2008 | 2007 | V |
| UT | PAC East | Summit-Lake Side | CT | 146 | 150 | NG | 2007 | 2007 | V |
| UT | PAC East | Summit-Lake Side | CT | 146 | 150 | NG | 2007 | 2007 | V |
| UT | PAC East | Summit-Lake Side | CA | 251 | 250 | NG | 2007 | 2007 | V |
| WY | PAC East | Mountain Wind | WT | 60 | 60 | WND | 2007 | 2007 | V |
| WY | PAC East | Mountain Wind | WT | 80 | 80 | WND | 2007 | 2007 | V |
| UT | PAC East | Pioneer Ridge | WT | 70 | 70 | WND | 2007 | 2007 | V |
| NWUW | PAC West | Marengo | WT | 140 | 140 | WND | 2007 | 2007 | V |
| NWUW | PGE | Port Westward | CT | 231 | 288 | NG | 2005 | 2007 | V |
| NWUW | PGE | Port Westward | CA | 127 | 138 | NG | 2005 | 2007 | V |
| NM | PNM | Afton | GT | -141 | -141 | NG | 2003 | 2007 | V |
| NM | PNM | Afton | CT | 141 | 141 | NG | 2003 | 2007 | V |
| NM | PNM | Afton | CA | 94 | 94 | NG | 2003 | 2007 | V |
| COE | PSCO | Spindle Hill | GT | 135 | 157 | NG | 2007 | 2007 | V |
| COE | PSCO | Spindle Hill | GT | 135 | 157 | NG | 2007 | 2007 | V |
| NWUW | PSE | Sierra Pacific | BM | 31 | 31 | WDS | 2007 | 2007 | V |
| SMUD | WASN | Roseville EP | CT | 43 | 43 | NG | 2006 | 2007 | V |
| SMUD | WASN | Roseville EP | CT | 43 | 43 | NG | 2006 | 2007 | V |
| SMUD | WASN | Roseville EP | CA | 80 | 80 | NG | 2006 | 2007 | V |
| PGEN | CISO | Buena Vista | WT | 38 | 38 | WND | 2007 | 2007 | TS |
| SDGE | CISO | Otay 3 | BM | 4 | 4 | LFG | 2007 | 2007 | TS |
| PGES | CISO | Marina-LFG2 | BM | 3 | 3 | LFG | 2007 | 2007 | TS |
| PGEN | CISO | Lake Mendocino | HY | 4 | 4 | WAT | 2007 | 2007 | TS |
| PGES | CISO | Midsun Repower | GT | 22 | 22 | NG | 2007 | 2007 | TS |

**Class 1 Additions**

| Area | Balancing Authority | Name | Unit Type | Name Plate Capability (MW) Summer | Winter | Fuel Type | Commercial Operation Dates Original | New | Status |
|---|---|---|---|---|---|---|---|---|---|
| AZ | APS | Cholla | ST | 11 | 11 | SUB | 2007 | 2007 | A |
| NWUW | AVA | Cabinet Gorge | HY | 11 | 11 | WAT | 1952 | 2007 | A |
| NWCB | BC Hydro | S Slocan | HY | 3 | 3 | WAT | 2005 | 2007 | A |
| NWCB | BC Hydro | Corra Linn | HY | 2 | 2 | WAT | 2006 | 2007 | A |
| SCE | CISO | Long Beach | GT | 65 | 65 | NG | 2007 | 2007 | RA |
| SCE | CISO | Long Beach | GT | 65 | 65 | NG | 2007 | 2007 | RA |
| SCE | CISO | Long Beach | GT | 65 | 65 | NG | 2007 | 2007 | RA |
| SCE | CISO | Long Beach | GT | 65 | 65 | NG | 2007 | 2007 | RA |
| PGEN | CISO | Jackson Valley | BM | 16 | 16 | WDS | 2007 | 2007 | RA |
| | | Wind Derates | | -1,293 | -1,293 | | | | |
| | | | **Additions for 2007** | 4,286 | 4,405 | | | | |
| NWCB | BC Hydro | Aberfeldie 2 | HY | 18 | 0 | WAT | 2008 | 2008 | U |
| ID | IPC | Treasure Valley | BM | 3 | 3 | OBG | 2008 | 2008 | U |
| ID | IPC | Lowline Midway | HY | 2 | 0 | WAT | 2007 | 2008 | U |
| ID | IPC | Raft River I | GE | 10 | 10 | GEO | 2006 | 2008 | U |
| NVS | NPC | Clark | GT | 52 | 52 | NG | 2008 | 2008 | U |
| NVS | NPC | Clark | GT | 52 | 52 | NG | 2008 | 2008 | U |
| NVS | NPC | Clark | GT | 52 | 52 | NG | 2008 | 2008 | U |
| NVS | NPC | Clark | GT | 52 | 52 | NG | 2008 | 2008 | U |
| NVS | NPC | Clark | GT | 52 | 52 | NG | 2008 | 2008 | U |
| NVS | NPC | Clark | GT | 52 | 52 | NG | 2008 | 2008 | U |
| NVS | NPC | Clark | GT | 52 | 52 | NG | 2008 | 2008 | U |
| NVS | NPC | Clark | GT | 52 | 52 | NG | 2008 | 2008 | U |
| COE | PSCO | Lamar Plt | ST | -25 | -25 | NG | 2008 | 2008 | U |
| COE | PSCO | Lamar Plt | ST | 25 | 25 | BIT | 2008 | 2008 | U |
| COE | PSCO | Lamar Plt | ST | 14 | 14 | BIT | 2008 | 2008 | U |
| NVN | SPP | TS Power | ST | 200 | 200 | SUB | 2007 | 2008 | U |
| NVN | SPP | Tracy CC | CC | 514 | 514 | NG | 2008 | 2008 | U |
| NWUW | BPA | Grays Harbor | CT | 170 | 170 | NG | 2003 | 2008 | V |
| NWUW | BPA | Grays Harbor | CT | 170 | 170 | NG | 2003 | 2008 | V |
| NWUW | BPA | Grays Harbor | CA | 260 | 260 | NG | 2003 | 2008 | V |
| PV | APS | Palo Verde | NP | 71 | 71 | NUC | 2005 | 2008 | A |
| NWCB | BC Hydro | S Slocan | HY | 3 | 3 | WAT | 2006 | 2008 | A |
| NWCB | BC Hydro | Corra Linn | HY | 2 | 2 | WAT | 2005 | 2008 | A |
| LDWP | LDWP | Castaic | PS | 26 | 26 | WAT | 2006 | 2008 | A |
| LDWP | LDWP | *Castaic derate | PS | -10 | -10 | WAT | 2006 | 2008 | A |
| COE | PSCO | Rawhide | ST | 8 | 8 | BIT | 2008 | 2008 | A |
| SMUD | MID | Hershey Cogen | GT | -5 | -5 | NG | 1994 | 2008 | D |
| NWUW | PAC West | Condit | HY | -7 | -7 | WAT | 2006 | 2008 | RT |
| NWUW | PAC West | Condit | HY | -7 | -7 | WAT | 2006 | 2008 | RT |
| | | | **Additions for 2008** | 1,857 | 1,837 | | | | |
| MXW | CFE | Pdte.Juárez | CC | 259 | 259 | NG | 2009 | 2009 | U |
| MXW | CFE | Baja California II | CC | 223 | 223 | NG | 2009 | 2009 | U |
| PGEN | CISO | Gateway | CC | 530 | 530 | NG | 2009 | 2009 | U |
| LDWP | LDWP | Pine Tree | WT | 120 | 120 | WND | 2004 | 2009 | U |
| NVS | NPC | Clark | GT | 52 | 52 | NG | 2009 | 2009 | U |
| NVS | NPC | Clark | GT | 52 | 52 | NG | 2009 | 2009 | U |
| NVS | NPC | Clark | GT | 52 | 52 | NG | 2009 | 2009 | U |
| NVS | NPC | Clark | GT | 52 | 52 | NG | 2009 | 2009 | U |
| AZ | SRP | Springerville | ST | 400 | 400 | SUB | 2010 | 2009 | U |
| NWUW | AVA | Noxon Rapids | HY | 12 | 12 | WAT | 1960 | 2009 | A |
| LDWP | LDWP | Castaic | PS | 0 | 0 | WAT | 2005 | 2009 | A |
| SMUD | MID | Woodland | GT | -48 | -50 | NG | 2009 | 2009 | RP |
| | | Wind Derates | | -108 | -108 | | | | |
| | | | **Additions for 2009** | 1,596 | 1,594 | | | | |

**Class 1 Additions**

| Area | Balancing Authority | Name | Unit Type | Name Plate Capability (MW) Summer | Winter | Fuel Type | Commercial Operation Dates Original | New | Status |
|---|---|---|---|---|---|---|---|---|---|
| MXW | CFE | Pdte.Juárez TG/TC | GT | 93 | 93 | NG | 2010 | 2010 | U |
| WY | PAC East | Two Elk | OT | 274 | 282 | WC | 2003 | 2010 | U |
| COE | PSCO | Comanche | ST | 750 | 780 | BIT | 2009 | 2010 | U |
| NWUW | AVA | Noxon Rapids | HY | 12 | 12 | WAT | 1959 | 2010 | A |
| LDWP | LDWP | Castaic | PS | 0 | 0 | WAT | 2003 | 2010 | A |
| NWUW | PAC West | Powerdale | HY | 0 | 0 | WAT | 1923 | 2010 | RT |
| SMUD | MID | Woodland | CT | -46 | -47 | NG | 2010 | 2010 | RP |
| SMUD | MID | Woodland | CA | -37 | -37 | NG | 2010 | 2010 | RP |
| SMUD | MID | Woodland | CT | 46 | 47 | NG | 2010 | 2010 | RP |
| SMUD | MID | Woodland | CT | 48 | 50 | NG | 2010 | 2010 | RP |
| SMUD | MID | Woodland | CA | 37 | 37 | NG | 2010 | 2010 | RP |
| | | | **Additions for 2010** | 1,177 | 1,217 | | | | |

# APPENDIX A-5-K



**Class 2 Additions**

| Area | Balancing Authority | Name | Unit Type | Net Capability MW Summer | Net Capability MW Winter | Fuel Type | Commercial Operation Dates Original | Commercial Operation Dates New | Status |
|---|---|---|---|---|---|---|---|---|---|
| COE | PSCO | DADS | BM | 1 | 1 | LFG | 2007 | 2007 | L |
| COE | PSCO | DADS | BM | 1 | 1 | LFG | 2007 | 2007 | L |
| COE | PSCO | DADS | BM | 1 | 1 | LFG | 2007 | 2007 | L |
| COE | PSCO | DADS | BM | 1 | 1 | LFG | 2007 | 2007 | L |
| NWUW | BPA | White Creek | WT | 200 | 200 | WND | 2006 | 2007 | T |
| NWUW | BPA | Leaning Juniper | WT | 100 | 100 | WND | 2007 | 2007 | T |
| NWUW | BPA | Goodnoe Hills | WT | 150 | 150 | WND | 2006 | 2007 | T |
| | | Wind Derates | | -383 | -383 | | | | |
| | | **Additions for 2007** | | 70 | 70 | | | | |
| NWCA | AESO | Conklin | GT | 85 | 85 | NG | 2006 | 2008 | L |
| PGEN | CISO | Bullard EC | GT | 201 | 201 | NG | 2008 | 2008 | L |
| PGES | CISO | Russell City EC Exp. | CC | 245 | 245 | NG | 2008 | 2008 | L |
| PGEN | CISO | Humboldt Repower | IC | 162 | 162 | NG | 2008 | 2008 | L |
| PGES | CISO | Starwood Power | GT | 119 | 119 | NG | 2008 | 2008 | L |
| COE | PSCO | Plains End II | IC | 8 | 8 | NG | 2008 | 2008 | L |
| COE | PSCO | Plains End II | IC | 8 | 8 | NG | 2008 | 2008 | L |
| COE | PSCO | Plains End II | IC | 8 | 8 | NG | 2008 | 2008 | L |
| COE | PSCO | Plains End II | IC | 8 | 8 | NG | 2008 | 2008 | L |
| COE | PSCO | Plains End II | IC | 8 | 8 | NG | 2008 | 2008 | L |
| COE | PSCO | Plains End II | IC | 8 | 8 | NG | 2008 | 2008 | L |
| COE | PSCO | Plains End II | IC | 8 | 8 | NG | 2008 | 2008 | L |
| COE | PSCO | Plains End II | IC | 8 | 8 | NG | 2008 | 2008 | L |
| COE | PSCO | Plains End II | IC | 8 | 8 | NG | 2008 | 2008 | L |
| COE | PSCO | Plains End II | IC | 8 | 8 | NG | 2008 | 2008 | L |
| COE | PSCO | Plains End II | IC | 8 | 8 | NG | 2008 | 2008 | L |
| COE | PSCO | Plains End II | IC | 8 | 8 | NG | 2008 | 2008 | L |
| COE | PSCO | Plains End II | IC | 8 | 8 | NG | 2008 | 2008 | L |
| COE | PSCO | Plains End II | IC | 8 | 8 | NG | 2008 | 2008 | L |
| NWUW | BPA | CEP Arlington | WT | 200 | 200 | WND | 2005 | 2008 | T |
| ID | IPC | Danskin | GT | 165 | 178 | NG | 2008 | 2008 | T |
| COE | PSCO | Colorado Green | WT | 75 | 75 | WND | 2008 | 2008 | T |
| | | Wind Derates | | -237 | -237 | | | | |
| | | **Additions for 2008** | | 1,130 | 1,143 | | | | |
| SCE | CISO | Walnut Creek | GT | 501 | 501 | NG | 2009 | 2009 | L |
| PGES | CISO | Eastshore EF | IC | 118 | 118 | NG | 2009 | 2009 | L |
| SCE | CISO | AES Highgrove | GT | 325 | 325 | NG | 2009 | 2009 | L |
| PGES | CISO | Panoche EC | GT | 401 | 401 | NG | 2009 | 2009 | L |
| SCE | CISO | Victorville 2 | CC | 571 | 571 | NG | 2009 | 2009 | L |
| PGEN | CISO | CPV Colusa | CC | 715 | 715 | NG | 2009 | 2009 | L |
| SDGE | CISO | South Bay Option 1 | CC | 650 | 650 | NG | 2009 | 2009 | L |
| NWCB | BC Hydro | Gordon M Shrum | HY | 30 | 30 | WAT | 2009 | 2009 | T |
| | | **Additions for 2009** | | 3,310 | 3,310 | | | | |
| NWCB | BC Hydro | Revelstoke | HY | 500 | 500 | WAT | 1999 | 2010 | L |
| SCE | CISO | Vernon | CC | 610 | 610 | NG | 2010 | 2010 | L |
| NWCB | BC Hydro | Gordon M Shrum | HY | 30 | 30 | WAT | 2010 | 2010 | T |
| NWCB | BC Hydro | Gordon M Shrum | HY | 30 | 30 | WAT | 2010 | 2010 | T |
| | | **Additions for 2010** | | 1,170 | 1,170 | | | | |
| NWCA | AESO | Keephills | ST | 450 | 450 | SUB | 2011 | 2011 | T |
| NWUW | AVA | Noxon Rapids | HY | 12 | 12 | WAT | 1959 | 2011 | A |
| LDWP | LDWP | Castaic | PS | 0 | 0 | WAT | 2011 | 2011 | A |
| | | **Additions for 2011** | | 462 | 462 | | | | |

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**Class 2 Additions**

| Area | Balancing Authority | Name | Unit Type | Net Capability MW Summer | Net Capability MW Winter | Fuel Type | Commercial Operation Dates Original | Commercial Operation Dates New | Status |
|---|---|---|---|---|---|---|---|---|---|
| NWUW | AVA | Noxon Rapids | HY | 12 | 12 | WAT | 1959 | 2012 | A |
| | | | **Additions for 2012** | 12 | 12 | | | | |
| COE | WACM | Knutson | GT | 64 | 77 | NG | 2013 | 2013 | A |
| COE | WACM | Knutson | GT | 64 | 77 | NG | 2013 | 2013 | A |
| COE | PSCO | Knutson | GT | -64 | -77 | NG | 2013 | 2013 | D |
| COE | PSCO | Knutson | GT | -64 | -77 | NG | 2013 | 2013 | D |
| | | | **Additions for 2013** | 0 | 0 | | | | |

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**Class 3 Additions**

| Area | Balancing Authority | Name | Unit Type | Net Capability MW Summer | Net Capability MW Winter | Fuel Type | Commercial Operation Dates Original | Commercial Operation Dates New | Status |
|---|---|---|---|---|---|---|---|---|---|
| NWUW | BPA | Nine Canyon III | WT | 32 | 32 | WND | 2007 | 2007 | P |
| SDGE | CISO | Cuyapaipe | WT | 117 | 117 | WND | 2007 | 2007 | P |
| SCE | CISO | Wintec III | WT | 12 | 12 | WND | 2007 | 2007 | P |
| SCE | CISO | Barren Ridge II | WT | 300 | 300 | WND | 2007 | 2007 | P |
| SCE | CISO | Caithness 251 Rep. | WT | 33 | 33 | WND | 2007 | 2007 | P |
| SCE | CISO | Ridgetop Repower | WT | 34 | 34 | WND | 2007 | 2007 | P |
| SCE | CISO | Sidewinder Mtn. | WT | 99 | 99 | WND | 2007 | 2007 | P |
| SCE | CISO | Windstar I Alt. | WT | 120 | 120 | WND | 2007 | 2007 | P |
| ID | IPC | Milner Dam | WT | 18 | 18 | WND | 2007 | 2007 | P |
| ID | IPC | Oregon Trails | WT | 11 | 11 | WND | 2006 | 2007 | P |
| ID | IPC | Pilgrim Stage | WT | 11 | 11 | WND | 2006 | 2007 | P |
| ID | IPC | Thousand Springs | WT | 11 | 11 | WND | 2006 | 2007 | P |
| ID | IPC | Tuana Gulch | WT | 11 | 11 | WND | 2006 | 2007 | P |
| ID | IPC | Burley Butte | WT | 11 | 11 | WND | 2006 | 2007 | P |
| ID | IPC | Cassia Gulch | WT | 19 | 19 | WND | 2007 | 2007 | P |
| ID | IPC | Cassia Wind | WT | 11 | 11 | WND | 2007 | 2007 | P |
| ID | IPC | Magic Wind | WT | 20 | 20 | WND | 2007 | 2007 | P |
| | | Wind Derate | | -813 | -813 | | | | |
| | | | **Additions for 2007** | 57 | 57 | | | | |
| NWCA | AESO | Blue Trail | WT | 30 | 30 | WND | 2006 | 2008 | P |
| NWCA | AESO | Blue Trail | WT | 30 | 30 | WND | 2006 | 2008 | P |
| NWCA | AESO | Summerview | WT | 60 | 60 | WND | 2005 | 2008 | P |
| NWCA | AESO | Waterton | WT | 75 | 75 | WND | 2007 | 2008 | P |
| NWCA | AESO | Waterton | WT | 75 | 75 | WND | 2007 | 2008 | P |
| NWCA | AESO | Waterton | WT | 75 | 75 | WND | 2007 | 2008 | P |
| NWCA | AESO | Waterton | WT | 75 | 75 | WND | 2007 | 2008 | P |
| NWUW | BPA | Klondike Phase 3 | WT | 79 | 79 | WND | 2006 | 2008 | P |
| NWUW | BPA | Combine Hills II | WT | 63 | 63 | WND | 2006 | 2008 | P |
| NWUW | BPA | Windy Point | WT | 250 | 250 | WND | 2008 | 2008 | P |
| PGEN | CISO | High Winds | WT | 38 | 38 | WND | 2008 | 2008 | P |
| PGES | CISO | Wellhead Firebaugh | GT | 50 | 50 | NG | 2008 | 2008 | P |
| PGEN | CISO | Wellhead Lathrop | CC | 60 | 60 | NG | 2008 | 2008 | P |
| SDGE | CISO | Tule Wind | WT | 201 | 201 | WND | 2008 | 2008 | P |
| SCE | CISO | Manzana | WT | 300 | 300 | WND | 2008 | 2008 | P |
| PGEN | CISO | Hatchet Ridge | WT | 102 | 102 | WND | 2008 | 2008 | P |
| SCE | CISO | Dillon Exp. | WT | 101 | 101 | WND | 2008 | 2008 | P |
| SCE | CISO | Windstar I | WT | 120 | 120 | WND | 2008 | 2008 | P |
| PGES | CISO | Henrietta II | GT | 97 | 97 | NG | 2008 | 2008 | P |
| SCE | CISO | SES Solar | SP | 850 | 850 | SUN | 2008 | 2008 | P |
| SDGE | CISO | San Diego Wind I | WT | 36 | 36 | WND | 2008 | 2008 | P |
| SDGE | CISO | Chula Vista Exp. | GT | 60 | 60 | NG | 2008 | 2008 | P |
| SDGE | CISO | SES Solar | SP | 300 | 300 | SUN | 2008 | 2008 | P |
| PGES | CISO | RMU Plant | GT | 100 | 100 | NG | 2008 | 2008 | P |
| PGEP | CISO | Los Esteros CEF II | CC | 140 | 140 | NG | 2008 | 2008 | P |
| SCE | CISO | Daggett Wind | WT | 80 | 80 | WND | 2008 | 2008 | P |
| SDGE | CISO | Rumorosa Wind | WT | 400 | 400 | WND | 2008 | 2008 | P |
| PGEN | CISO | Rocklin Peaker | GT | 117 | 117 | NG | 2008 | 2008 | P |
| SCE | CISO | Long Beach Peaker | GT | 405 | 405 | NG | 2008 | 2008 | P |
| SDGE | CISO | Pala EF | GT | 99 | 99 | NG | 2008 | 2008 | P |
| SDGE | CISO | Margarita EF | GT | 99 | 99 | NG | 2008 | 2008 | P |
| PGES | CISO | East Altamont Opt2 | GT | 531 | 531 | NG | 2008 | 2008 | P |
| PGES | CISO | Wellhead McCall | GT | 300 | 300 | NG | 2008 | 2008 | P |
| PGES | CISO | San Joaquin Vly | CC | 791 | 791 | NG | 2008 | 2008 | P |
| SCE | CISO | Alta 7 Antelope | WT | 100 | 100 | WND | 2008 | 2008 | P |
| SDGE | CISO | Larkspur 3 | GT | 43 | 43 | NG | 2008 | 2008 | P |
| PGEP | CISO | SF Airport | GT | 49 | 49 | NG | 2008 | 2008 | P |

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**Class 3 Additions**

| Area | Balancing Authority | Name | Unit Type | Net Capability MW Summer | Net Capability MW Winter | Fuel Type | Commercial Operation Dates Original | Commercial Operation Dates New | Status |
|---|---|---|---|---|---|---|---|---|---|
| PGEP | CISO | S. F. ERP | GT | 145 | 145 | NG | 2008 | 2008 | P |
| SCE | CISO | Ocotillo | CC | 850 | 850 | NG | 2008 | 2008 | P |
| SDGE | CISO | Boulder Wash Wind | WT | 160 | 160 | WND | 2008 | 2008 | P |
| PGEN | CISO | Tesla Sub | CC | 1,156 | 1,156 | NG | 2008 | 2008 | P |
| PGEN | CISO | Shiloh Wind | WT | 150 | 150 | WND | 2008 | 2008 | P |
| PGEN | CISO | Geysers Wind | WT | 201 | 201 | WND | 2008 | 2008 | P |
| PGEN | CISO | Wildhorse | WT | 210 | 210 | WND | 2008 | 2008 | P |
| SCE | CISO | Blythe EP Phase II | CC | 560 | 560 | NG | 2008 | 2008 | P |
| SCE | CISO | Indigo Winds | WT | 50 | 50 | WND | 2008 | 2008 | P |
| SCE | CISO | Mojave Winds | WT | 150 | 150 | WND | 2008 | 2008 | P |
| SCE | CISO | UPC Grand View | WT | 150 | 150 | WND | 2008 | 2008 | P |
| SDGE | CISO | Encina Peaking | GT | 300 | 300 | NG | 2008 | 2008 | P |
| PGEN | CISO | Shiloh III | WT | 200 | 200 | WND | 2008 | 2008 | P |
| SCE | CISO | Granite Mtn. | WT | 60 | 60 | WND | 2008 | 2008 | P |
| SDGE | CISO | Olivenhain-Hodges | PS | 40 | 40 | WAT | 2008 | 2008 | P |
| SCE | CISO | West Fry Wind | WT | 60 | 60 | WND | 2008 | 2008 | P |
| SCE | CISO | Cal. Solar One | SP | 220 | 220 | SUN | 2008 | 2008 | P |
| SDGE | CISO | Tule II | WT | 300 | 300 | WND | 2008 | 2008 | P |
| PGES | CISO | Pacific Renewable | WT | 120 | 120 | WND | 2008 | 2008 | P |
| PGEN | CISO | Ripon Exp. | GT | 97 | 97 | NG | 2008 | 2008 | P |
| SDGE | CISO | BME Otay Mesa | GE | 27 | 27 | GEO | 2008 | 2008 | P |
| PGES | CISO | Daggett Wind II | WT | 201 | 201 | WND | 2008 | 2008 | P |
| SCE | CISO | Suncreek | WT | 220 | 220 | WND | 2008 | 2008 | P |
| SCE | CISO | Lehigh | WT | 180 | 180 | WND | 2008 | 2008 | P |
| SCE | CISO | Pacific Wind | WT | 250 | 250 | WND | 2008 | 2008 | P |
| SCE | CISO | Cabazon Ridge | WT | 150 | 150 | WND | 2008 | 2008 | P |
| IID | IID | Niland | GT | 45 | 45 | NG | 2007 | 2008 | P |
| IID | IID | Niland | GT | 45 | 45 | NG | 2009 | 2008 | P |
| ID | IPC | Golden Valley | WT | 11 | 11 | WND | 2007 | 2008 | P |
| ID | IPC | Elkhorn Wind | WT | 100 | 100 | WND | 2008 | 2008 | P |
| ID | IPC | Lava Beds | WT | 18 | 18 | WND | 2006 | 2008 | P |
| ID | IPC | Notch Butte | WT | 18 | 18 | WND | 2006 | 2008 | P |
| ID | IPC | Salmon Falls | WT | 21 | 21 | WND | 2007 | 2008 | P |
| LDWP | LDWP | Haynes | ST | 35 | 35 | NG | 2008 | 2008 | P |
| NM | PNM | Valencia GT | GT | 140 | 140 | NG | 2008 | 2008 | P |
| COE | PSCO | Rawhide | GT | 138 | 138 | NG | 2008 | 2008 | P |
| NWUW | PSE | Ormat | OT | 5 | 5 | OTH | 2007 | 2008 | P |
| SMUD | SMUD | Solano Wind | WT | 63 | 63 | WND | 2006 | 2008 | P |
| AZ | TEP | Unidentified | GT | 45 | 45 | NG | 2008 | 2008 | P |
| AZ | TEP | Unidentified | GT | 45 | 45 | NG | 2008 | 2008 | P |
| AZ | TEP | SGS Solar | PV | 1 | 1 | SUN | 2007 | 2008 | P |
| | | Wind Derates | | -4,979 | -5,000 | | | | |
| | | | **Additions for 2008** | 8,338 | 18,317 | | | | |
| NWUW | BPA | Biglow Canyon | WT | 150 | 150 | WND | 2006 | 2009 | P |
| NWUW | BPA | Biglow Canyon | WT | 124 | 124 | WND | 2006 | 2009 | P |
| NWUW | BPA | Shepards Flat | WT | 250 | 250 | WND | 2009 | 2009 | P |
| NWUW | BPA | Reardon Twin Buttes | WT | 75 | 75 | WND | 2009 | 2009 | P |
| NWUW | BPA | Kittitas Valley | WT | 125 | 125 | WND | 2009 | 2009 | P |
| NWUW | BPA | Big Horn Wind | WT | 100 | 100 | WND | 2009 | 2009 | P |
| NWUW | BPA | Seven Mile Hill | WT | 50 | 50 | WND | 2006 | 2009 | P |
| SCE | CISO | Casa Diablo 4 | GE | 17 | 17 | GEO | 2009 | 2009 | P |
| SCE | CISO | Barren Ridge | WT | 201 | 201 | WND | 2009 | 2009 | P |
| SDGE | CISO | San Diego CPGS | CC | 750 | 750 | NG | 2009 | 2009 | P |
| SCE | CISO | Lake Elsinore | PS | 500 | 500 | WAT | 2009 | 2009 | P |
| SCE | CISO | South Point | CC | 550 | 550 | NG | 2009 | 2009 | P |
| SDGE | CISO | Miramar EF II | GT | 49 | 49 | NG | 2009 | 2009 | P |

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**Class 3 Additions**

| Area | Balancing Authority | Name | Unit Type | Net Capability MW Summer | Net Capability MW Winter | Fuel Type | Commercial Operation Dates Original | Commercial Operation Dates New | Status |
|---|---|---|---|---|---|---|---|---|---|
| PGES | CISO | S. Kern Front CG | GT | 94 | 94 | NG | 2009 | 2009 | P |
| PGEN | CISO | Wilbur Power CC | CC | 157 | 157 | NG | 2009 | 2009 | P |
| SCE | CISO | Vernon Power Exp. | GT | 304 | 304 | NG | 2009 | 2009 | P |
| PGES | CISO | Collinsville | WT | 30 | 30 | WND | 2009 | 2009 | P |
| SCE | CISO | Palmdale | CC | 570 | 570 | NG | 2009 | 2009 | P |
| SDGE | CISO | Otay Mesa | CC | 615 | 615 | NG | 2002 | 2009 | P |
| PGES | CISO | Russell City EC | GT | 361 | 361 | NG | 2009 | 2009 | P |
| SCE | CISO | Coram Brodie Wind | WT | 51 | 51 | WND | 2009 | 2009 | P |
| SCE | CISO | Copper Mtn. | CC | 634 | 634 | NG | 2009 | 2009 | P |
| PGEN | CISO | Point Sal Wind | WT | 105 | 105 | WND | 2009 | 2009 | P |
| PGEN | CISO | Bear River Wind | WT | 70 | 70 | WND | 2009 | 2009 | P |
| PGES | CISO | Liberty V Lost Hills | ST | 20 | 20 | NG | 2009 | 2009 | P |
| SCE | CISO | North Sky River Wind | WT | 297 | 297 | WND | 2009 | 2009 | P |
| SCE | CISO | Genesis Solar | SP | 500 | 500 | SUN | 2009 | 2009 | P |
| SCE | CISO | North Sky River II | WT | 362 | 362 | WND | 2009 | 2009 | P |
| SCE | CISO | Mojave Solar Park 1 | SP | 635 | 635 | SUN | 2009 | 2009 | P |
| SCE | CISO | Avalon Wind | WT | 400 | 400 | WND | 2009 | 2009 | P |
| SCE | CISO | CPC East | WT | 550 | 550 | WND | 2009 | 2009 | P |
| SCE | CISO | CPC West | WT | 600 | 600 | WND | 2009 | 2009 | P |
| SCE | CISO | Lucchese | WT | 160 | 160 | WND | 2009 | 2009 | P |
| SCE | CISO | Eagle Mtn. PV | PV | 150 | 150 | SUN | 2009 | 2009 | P |
| SCE | CISO | Eagle Mtn. PV | PV | 400 | 400 | SUN | 2009 | 2009 | P |
| SCE | CISO | Coram Brodie Phase 2 | WT | 51 | 51 | WND | 2009 | 2009 | P |
| NM | EPE | Newman | GT | 70 | 70 | NG | 2008 | 2009 | P |
| IID | IID | Unidentified | OT | 15 | 15 | OTH | 2009 | 2009 | P |
| IID | IID | Unidentified | GE | 20 | 20 | GEO | 2009 | 2009 | P |
| IID | IID | El Centro | ST | -48 | -48 | RFO | 2006 | 2009 | P |
| IID | IID | El Centro | CA | 34 | 34 | NG | 2006 | 2009 | P |
| IID | IID | El Centro | CT | 87 | 87 | NG | 2006 | 2009 | P |
| MT | NWMT | Bull Mountain | ST | 350 | 350 | LIG | 2008 | 2009 | P |
| MT | NWMT | Bull Mountain | ST | 350 | 350 | LIG | 2008 | 2009 | P |
| MT | NWMT | Southern MT Elec. | ST | 268 | 268 | LIG | 2009 | 2009 | P |
| NM | PNM | Biomass | BM | 32 | 32 | WDS | 2009 | 2009 | P |
| NM | PNM | Delta Person | GT | -132 | -132 | NG | 2009 | 2009 | P |
| NM | PNM | Delta Person | CT | 132 | 132 | NG | 2009 | 2009 | P |
| NM | PNM | Delta Person | CA | 72 | 72 | NG | 2009 | 2009 | P |
| COE | PSCO | Squirrel | CC | 500 | 531 | NG | 2009 | 2009 | P |
| AZ | TEP | SGS Solar | PV | 1 | 1 | SUN | 2008 | 2009 | P |
| | | Wind Derates | | -3,447 | -3,447 | | | | |
| | | **Additions for 2009** | | 8,361 | 8,392 | | | | |
| MXW | CFE | Cerro Prieto V | GE | 107 | 107 | GEO | 2010 | 2010 | P |
| SCE | CISO | Argonaut Wind | WT | 50 | 50 | WND | 2010 | 2010 | P |
| SCE | CISO | Crossroads | WT | 140 | 140 | WND | 2010 | 2010 | P |
| SCE | CISO | Harper Lake Solar | SP | 300 | 300 | SUN | 2010 | 2010 | P |
| SCE | CISO | Granite Fox | ST | 1,200 | 1,200 | BIT | 2010 | 2010 | P |
| SCE | CISO | DPT 1 | SP | 100 | 100 | SUN | 2010 | 2010 | P |
| SCE | CISO | Etiwanda Exp. | CC | 698 | 698 | NG | 2010 | 2010 | P |
| SCE | CISO | Fontana EC | GT | 330 | 330 | NG | 2010 | 2010 | P |
| SCE | CISO | Pastoria Exp/ II | GT | 200 | 200 | NG | 2010 | 2010 | P |
| SCE | CISO | Mojave Solar Park 2 | SP | 565 | 565 | SUN | 2010 | 2010 | P |
| SCE | CISO | Alta 6 | WT | 500 | 500 | WND | 2010 | 2010 | P |
| PGES | CISO | KRCD Community PP | CC | 565 | 565 | NG | 2010 | 2010 | P |
| SCE | CISO | Carson Hydrogen PP | CC | 614 | 614 | NG | 2010 | 2010 | P |
| NM | EPE | Newman | GT | 70 | 70 | NG | 2009 | 2010 | P |
| IID | IID | Unidentified | GE | 50 | 50 | GEO | 2010 | 2010 | P |
| ID | IPC | Shoshone Falls | HY | -1 | -1 | WAT | 2010 | 2010 | P |

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**Class 3 Additions**

| Area | Balancing Authority | Name | Unit Type | Net Capability MW Summer | Net Capability MW Winter | Fuel Type | Commercial Operation Dates Original | Commercial Operation Dates New | Status |
|---|---|---|---|---|---|---|---|---|---|
| ID | IPC | Shoshone Falls | HY | 0 | 0 | WAT | 2010 | 2010 | P |
| ID | IPC | Shoshone Falls | HY | 64 | 64 | WAT | 2010 | 2010 | P |
| AZ | TEP | Unidentified | GT | 150 | 150 | NG | 2008 | 2010 | P |
| AZ | TEP | SGS Solar | PV | 2 | 2 | SUN | 2009 | 2010 | P |
| SMUD | WASN | Redding Power | CT | 44 | 46 | NG | 2010 | 2010 | P |
| | | Wind Derates | | -649 | -649 | | | | |
| | | **Additions for 2010** | | 5,099 | 5,100 | | | | |
| NWCB | BC Hydro | Waneta Expansion | HY | 435 | 435 | WAT | 2011 | 2011 | P |
| MXW | CFE | Baja California III | CC | 288 | 288 | NG | 2011 | 2011 | P |
| SCE | CISO | Green Borders | GE | 62 | 62 | GEO | 2011 | 2011 | P |
| SCE | CISO | SES Solar Seven | SP | 1,200 | 1,200 | SUN | 2011 | 2011 | P |
| SDGE | CISO | SES Solar Two Exp. | SP | 600 | 600 | SUN | 2011 | 2011 | P |
| PGEN | CISO | Solano Wind Phase 3 | WT | 126 | 126 | WND | 2011 | 2011 | P |
| SCE | CISO | SES Solar Three | SP | 550 | 550 | SUN | 2011 | 2011 | P |
| SCE | CISO | Green Borders II | GE | 90 | 90 | GEO | 2011 | 2011 | P |
| SCE | CISO | Searchlight 1 | WT | 1,500 | 1,500 | WND | 2011 | 2011 | P |
| NM | EPE | Newman | GT | -70 | -70 | NG | 2010 | 2011 | P |
| NM | EPE | Newman | GT | -70 | -70 | NG | 2010 | 2011 | P |
| NM | EPE | Newman | CT | 70 | 70 | NG | 2010 | 2011 | P |
| NM | EPE | Newman | CT | 70 | 70 | NG | 2010 | 2011 | P |
| NM | EPE | Newman | CA | 148 | 148 | NG | 2010 | 2011 | P |
| SMUD | SMUD | Solano Wind | WT | 105 | 105 | WND | 2009 | 2011 | P |
| AZ | TEP | SGS Solar | PV | 1 | 1 | SUN | 2010 | 2011 | P |
| WY | WACM | Dry Fork | ST | 385 | 385 | BIT | 2011 | 2011 | P |
| | | Wind Derates | | -1,587 | -1,622 | | | | |
| | | **Additions for 2011** | | 3,903 | 3,868 | | | | |
| IID | IID | El Centro | ST | -80 | -80 | RFO | 2009 | 2012 | P |
| IID | IID | El Centro | CA | 80 | 80 | NG | 2009 | 2012 | P |
| IID | IID | El Centro | CT | 170 | 170 | NG | 2009 | 2012 | P |
| UT | PAC East | Hunter | ST | 575 | 575 | BIT | 2011 | 2012 | P |
| NM | PNM | Las Vegas GT | GT | -18 | -18 | DFO | 2007 | 2012 | P |
| NVN | SPP | Ely EC | ST | 750 | 750 | BIT | 2012 | 2012 | P |
| AZ | TEP | Bowie | OT | 600 | 600 | BIT | 2012 | 2012 | P |
| AZ | TEP | SGS Solar | PV | 2 | 2 | SUN | 2011 | 2012 | P |
| COE | WACM | Holcomb | ST | 600 | 600 | BIT | 2012 | 2012 | P |
| | | **Additions for 2012** | | 2,679 | 2,679 | | | | |
| MXW | CFE | Baja California IV | CC | 288 | 288 | NG | 2012 | 2013 | P |
| SCE | CISO | SES Solar Six | SP | 1,400 | 1,400 | SUN | 2013 | 2013 | P |
| NM | EPE | Rio Grande | ST | -48 | -48 | NG | 2008 | 2013 | P |
| NM | EPE | Newman | GT | 70 | 70 | NG | 2013 | 2013 | P |
| LDWP | LDWP | Haynes | ST | -322 | -322 | NG | 2013 | 2013 | P |
| LDWP | LDWP | Haynes | ST | -278 | -278 | NG | 2013 | 2013 | P |
| LDWP | LDWP | Haynes | CC | 600 | 600 | NG | 2013 | 2013 | P |
| MT | NWMT | Nelson Creek | ST | 250 | 250 | LIG | 2010 | 2013 | P |
| MT | NWMT | Nelson Creek | ST | 250 | 250 | LIG | 2010 | 2013 | P |
| AZ | TEP | Unidentified | GT | 150 | 150 | NG | 2010 | 2013 | P |
| AZ | TEP | SGS Solar | PV | 2 | 2 | SUN | 2012 | 2013 | P |
| COE | WACM | Holcomb | ST | 600 | 600 | BIT | 2013 | 2013 | P |
| | | **Additions for 2013** | | 2,962 | 2,962 | | | | |
| AZ | APS | Cholla | ST | 450 | 450 | SUB | 2014 | 2014 | P |
| NM | EPE | Rio Grande | ST | -45 | -45 | NG | 2009 | 2014 | P |
| NM | EPE | Newman | ST | -81 | -82 | NG | 2014 | 2014 | P |

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**Class 3 Additions**

| Area | Balancing Authority | Name | Unit Type | Net Capability MW Summer | Net Capability MW Winter | Fuel Type | Commercial Operation Dates Original | Commercial Operation Dates New | Status |
|---|---|---|---|---|---|---|---|---|---|
| NM | EPE | Newman | GT | -70 | -70 | NG | 2014 | 2014 | P |
| NM | EPE | Newman | CT | 70 | 70 | NG | 2014 | 2014 | P |
| NM | EPE | Newman | CT | 70 | 70 | NG | 2014 | 2014 | P |
| NM | EPE | Newman | CA | 148 | 148 | NG | 2014 | 2014 | P |
| IID | IID | Unidentified | OT | 5 | 5 | OTH | 2014 | 2014 | P |
| LDWP | LDWP | Scattergood | ST | -450 | -450 | NG | 2014 | 2014 | P |
| LDWP | LDWP | Scattergood | CC | 450 | 450 | NG | 2014 | 2014 | P |
| SMUD | SMUD | Iowa Hill | PS | 390 | 390 | WAT | 2014 | 2014 | P |
| | | | **Additions for 2014** | 937 | 936 | | | | |
| AZ | APS | Cholla | ST | 450 | 450 | SUB | 2015 | 2015 | P |
| MXW | CFE | Baja California V | CC | 279 | 279 | NG | 2015 | 2015 | P |
| IID | IID | Unidentified | OT | 20 | 20 | OTH | 2015 | 2015 | P |
| NVN | SPP | Ely EC | ST | 750 | 750 | BIT | 2015 | 2015 | P |
| | | | **Additions for 2015** | 1,499 | 1,499 | | | | |
| MXW | CFE | Baja California VI | GT | 156 | 156 | NG | 2016 | 2016 | P |
| NM | EPE | Newman | ST | -82 | -83 | NG | 2016 | 2016 | P |
| NM | EPE | Newman | GT | 70 | 70 | NG | 2016 | 2016 | P |
| NM | EPE | Newman | GT | 70 | 70 | NG | 2016 | 2016 | P |
| | | | **Additions for 2016** | 214 | 213 | | | | |

## Definitions of Generation Addition Codes

### UNIT TYPE

| | |
|---|---|
| HY | Hydro – Conventional |
| PS | Hydro – Pumped Storage |
| ST | Steam Turbine – Non-Nuclear |
| NP | Steam Turbine – Nuclear |
| GT | Combustion Turbine |
| CA | Combined Cycle – Steam Portion |
| CT | Combined Cycle – Combustion Turbine Portion |
| CS | Combined Cycle – Single Shaft |
| CC | Combined Cycle – Total Unit |
| GE | Geothermal |
| IC | Internal Combustion |
| FC | Fuel Cell |
| BM | Biomass |
| PV | Solar Power – Photovoltaic |
| SP | Solar Power – Thermal |
| SO | Solar Power – Other |
| WT | Wind Power |
| CE | Compressed Air Energy Storage |

### FUEL TYPE

| | |
|---|---|
| BIT | Bituminous Coal |
| SUB | Sub-Bituminous Coal |
| LIG | Lignite Coal |
| WC | Waste Coal |
| SC | Synthetic Coal-based Fuel |
| PC | Petroleum Coke |
| DFO | Distillate Fuel Oil |
| JF | Jet Fuel |
| KER | Kerosene |
| RFO | Residual Fuel oil |
| WO | Waste Oil |
| NG | Natural Gas |
| PG | Propane |
| BFG | Blast Furnace Gas |
| OG | Other Gas (coke oven, refinery, etc.) |
| NUC | Nuclear |
| GEO | Geothermal Steam |
| WAT | Water-base ratings on median hydro conditions |
| AB | Agriculture Crop Byproducts |
| BLQ | Black Liquor |
| LFG | Landfill Gas |
| MSW | Municipal Solid Waste |
| OBL | Other Biomass Liquids |
| OBS | Other Biomass Solids |
| OBG | Other Biomass Gases (methane) |
| PUR | Purchased Steam |

FUEL TYPE (Continued)

SLW Sludge Waste
TDF Tires
WDL Wood or Wood Waste, Liquid
WDS Wood or Wood Waste, Solid
SUN Sun
WND Wind

**STATUS CODE (As reported in the data submittal and as classified by LRS for the PSA)**

**Class 1 Status Codes**

U Under active construction, less than or equal to 50% complete (based on construction time to first electric date)
V Under active construction, more than 50% complete (based on construction time to first electric date)
TS Construction complete, but not yet in commercial operation (including low power testing of nuclear units)
A Generator capability increased (re-rated or relicensed)
D Generator capability decreased (re-rated or relicensed)
M Generator to be put in deactivated shutdown status
RA Previously retired or deactivated generator planned for reactivation
RT Existing generator scheduled for retirement
FC Existing generator planned for conversion to another fuel or energy source
RP Proposed for life extension or repowering
CO Change of ownership (including change of shares of jointly-owned units)

**Class 2 Status Codes**

L Regulatory approval pending but not under active construction (started site preparation)
T Regulatory approval received but not under active construction
A Generator capability increased (re-rated or relicensed) (Beyond Class 1 Timeframe)
D Generator capability decreased (re-rated or relicensed) (Beyond Class 1 Timeframe)

**Class 3 Status Codes**

P Planned for installation but not under active construction
IP Planned generator canceled or indefinitely postponed

# APPENDIX A-5-K

APPENDIX A-5-L

*Western Electricity Coordinating Council*

# WECC
# Loads and Resources Data Collection
# Instruction Manual

**Loads and Resources Subcommittee**

**September 2007**

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**NOTE: There is a 2007 Data Collection Workshop scheduled on October 9, 2007 in Salt Lake City. The Workshop will include a Genesys link.**

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## Introduction and Overview

### Purpose

This Instruction Manual ("Manual" or "the Manual") provides instructions for reporting the loads and resources (L&R) information which WECC requests from all balancing authorities in the Western Interconnection (WI). The information is used for a variety of analytic and reporting purposes, and appears in the following WECC publications:

- *Information Summary*
- *Ten-Year Coordinated Plan Summary*
- *Summary of Estimated Loads and Resources* , and
- *Existing Generation and Significant Additions and Changes to System Facilities.*

In addition to these publications, portions of the WECC L&R information are used by NERC in its reliability assessment reports and on its website. The information is the basis for the resource adequacy evaluation contained in WECC's Power Supply Assessment (PSA), which the WECC Board of Directors ("the BOD") considers for approval in December of each year.

Finally, portions of the information are reported to the U.S. Department of Energy's Energy Information Administration (EIA) in satisfaction of its Form EIA-411 filing requirements, and annual and seasonal filings to NERC under its Standards and Guides compliance templates.

**Important Note to Member and Balancing Authority Representatives**: For those who will use the Manual as a guide in developing their 2007 data submittal, we remind you that significant changes were made in the 2006 Manual. As applied in your 2006 submittal and applicable to the 2007 submittal, changes include modifications to the tabs in the Excel Workbook, new codes used to characterize the status of generation additions, revised methods for reporting de-rated capacity, the addition of a code to report DSM load that was unserved, and a more specific definitions of firm transfers. Also, there is no longer a numerical code for planned purchases and instead you are asked to describe and document purchases and other descriptive information in the Narrative Information Request (NIR) that is provided as a separate document and as Attachment E to this Manual. We note that WECC's Planning Coordination Committee (PCC) and the BOD have approved Exhibit B to WECC's Information Disclosure Policy. This policy guides confidentiality protection related to L&R data. Exhibit B is provided in Attachment G of the Manual.

There have been several additional changes adopted for this year's L&R data collection. These changes include the addition of a request concerning monthly wind capacity factors in the Narrative Information Request document, and the request for two additional years of monthly forecast energy load data (for a total of four years of monthly forecast energy load data). There is no longer a numerical code for planned purchases and instead you are asked to describe and document purchases and other descriptive information in the Narrative Information Request document. As in the past, reporting areas may aggregate transfer and maintenance data for multiple zones. In addition to the loads and resources data, the Loads and Resources Subcommittee is requesting that reporting entities provide additional information as specified in the attached Narrative Information Request document NIR2007a.doc.

**Information Reporting Responsibility**

Planning Coordination Committee representatives are responsible for reporting Loads and Resources information for their organizations. It is possible that some of the information requested in the Manual may originate from areas of the reporting organization that are separated by Standards of Conduct (SOC) requirements.

**PCC Representatives of Control Area Operators**

The PCC representatives of the 32 organizations that operate the 36 balancing authorities in the WI are responsible for reporting the requested information. The L&R information are for the entire control area and are to include both the control area operator organization's information and information for all non-control area operator entities within the control area. The non-control area operator entity information includes planning information such as generation additions for both utilities and independent power producers, load forecasts and planning reserves of load serving entities, contractual firm transfers, and scheduled maintenance outages. The PCC representatives of the non-control area operator entities are responsible for reporting their organizations' information to the control area operators and for developing appropriate data collection procedures to ensure that all requested information is obtained from the appropriate non-control area operator entities and that there is no duplication or double reporting of the information. It is important to note that when submitting customer demand data, each entity supplying this data to their L & R contact shall count its customer demand once and only once.

**PCC Representatives of Non-control Area Operator Entities**

The PCC representatives of non-control area operator entities are responsible for responding to control area operator requests for planning information such as generation additions, load forecasts and planning reserves, contractual firm transfers, and scheduled maintenance outages.

PCC representatives may designate reporting contacts within their organizations. The designated reporting contacts will be asked to provide the requested information to the WECC Staff by the established due dates and answer questions that may arise concerning that information. However, the PCC representatives are ultimately responsible for the quality and timeliness of the data reported for their organizations.

**Information Requirements and Manual overview**

Information required includes:

Existing and planned generation units[1]
Peak demands, resources, resource outages, transfers, and planning reserve
Energy loads[1]

[1] Generation data and future year forecast data are due November 16, 2007; actual year data are due in February (see Attachment A – Schedule of Data Due Dates)

This Manual consists of five attachments and associated appendices. Attachment A identifies due dates for the 2007 reporting. Attachment B consists of an explanation of pages and terms found in the Excel Workbook (the "Interactive Excel Workbook") used to collect data requested in Attachments C and D. Attachment C contains instructions for reporting existing and planned generation capacity. Attachment D is the instruction for reporting peak demands, energy loads, and peak resources (including outages, transfers and other data).[2]

Several data reporting entities periodically prepare integrated resource plans (IRPs). The Narrative Information Request document, described in the following sub-section, provides a mechanism to explain the differences, if any, between the L&R data reported to WECC and the information presented in most recent IRP data.

**Narrative Information Request**

Additional information is being requested for selected items to allow for increased understanding regarding consistency of WECC L&R analyses among assumptions used in transmission expansion planning, integrated resource planning and other related processes. Specific topics and references to page numbers for which documentation is requested are identified in separate instructions called Narrative Information Request (NIR) document. This separate document should be submitted in parallel with the completed Interactive Excel Workbook to respond to the complete information request.

**Power Supply Assessment Information Requirements**

A separate request for additional data needed to complete the PSA will be distributed soon. This request will include information such as transfer constraints, weather sensitive load parameters, historical weather extremes, commitment status of selected units and other information necessary to assess adequacy under a range of future conditions

**Post-Season Assessment Information Requirements**

Monthly actual peak demands for June, July, August, and September will be requested each fall and monthly actual peak demands for January and February will be requested each spring. The specific due dates for this data are not presented in Attachment A as they will be dependent on dates not yet established by NERC.

**Data Confidentiality**

Exhibit B of the WECC Reliability Information Sharing Policy addresses confidentiality procedures for L&R data. Exhibit B is contained in Appendix G. of this Manual. The Loads and Resources Subcommittee will follow the direction of the Board regarding data confidentiality.

[2] The existing and planned generation data are due prior to the due date for the EIA-860 filing. Since both the DOE and WECC requests ask for almost the same information, it is recommended that WECC member systems internally coordinate their existing and planned generation data reporting.

Data, except as specified in Exhibit B attached, will be considered non-confidential. Exhibit B, Section C.1 states the following. "The following information will be treated as confidential under the "WECC Reliability Information Sharing Policy, Section D – Protecting Confidential, Privileged, and Proprietary Information" (approved by the BOD on December 1, 2005): first three years of future data on projected peak demand, energy load, and scheduled outages. These data will remain confidential for three years from the date of designation, after which the data will become non-confidential. Future year peak demands, future year energy load, and future year scheduled outages data beyond three years will ***not*** be deemed confidential."

**Data Submission**

**It is important to note these instructions are being released earlier than in past years and significantly longer time is being allowed for submission (see the due dates in Attachment A).** The completed Attachment B Interactive Excel Workbook should be sent via e-mail to WECC, accompanied by the Narrative Information Request response document. The LRS procedures specify that the LRS Chair will contact the PCC representatives of reporting entities that have not submitted their data in accordance with the Attachment A schedule of data due dates. The LRS Chair and PCC chairs will also contact the PCC representatives of reporting entities that have provided data that are incomplete or are inconsistent with these reporting instructions.

**List of Electric Utility Organizations within the WECC Region**

It is requested that the control area operator organization and all non-control area operator entities within the control area review the List of Electric Utility Organizations within the WECC Region (see Appendix D) and provide any updates or changes to the contact below.

**Workshop and Comments on this Manual**

**A workshop has been scheduled for October 9, 2007. This will be in Salt Lake City, and a Genesys link will also be provided.**

Questions on data reporting, or suggestions for improving the Instruction Manual, should be directed to WECC staff: Layne Brown and Dick Simons at (801) 582-0353 (lbrown @ wecc.biz dick@wecc.biz ).

# Attachment A: Schedule of Data Due Dates

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## SCHEDULE OF DATA DUE DATES

| DATA TYPE | DUE DATES | REQUESTING ENTITY | REPORTS WHERE DATA APPEARS |
|---|---|---|---|
| Existing Generation Data and Generation Additions Data | November 16 | WECC | Existing Generation and Significant Additions and Changes to System Facilities<br>Power Supply Assessment<br>10-Year Coordinated Plan Summary<br>Information Summary |
| | | NERC | Seasonal Assessments<br>Electricity Supply and Demand Database |
| Actual Year Resources Data | November 16 | WECC | Summary of Estimated Loads and Resources<br>10-Year Coordinated Plan Summary |
| | | NERC | Seasonal and Long-Term Assessments<br>Electricity Supply and Demand Database |
| Future Years Peak Demand, Resources, Scheduled Outages, Transfers, and Planning Reserve Data | November 16 | WECC | Summary of Estimated Loads and Resources<br>Power Supply Assessment<br>Information Summary<br>10-Year Coordinated Plan Summary |
| | | NERC | Seasonal and Long-Term Assessments<br>Electricity Supply and Demand Database |
| Future Years Energy Load Data | November 16 | WECC | Summary of Estimated Loads and Resources<br>Information Summary<br>10-Year Coordinated Plan Summary |
| | | NERC | Electricity Supply and Demand Database |

# APPENDIX A-5-L

## SCHEDULE OF DATA DUE DATES

| DATA TYPE | DUE DATES | REQUESTING ENTITY | REPORTS WHERE DATA APPEARS |
|---|---|---|---|
| Actual Year Peak Demands, Outages, and Transfers Data | February 8 | WECC | Summary of Estimated Loads and Resources<br>10-Year Coordinated Plan Summary<br>Information Summary |
| | | NERC | Seasonal and Long-Term Assessments<br>Electricity Supply and Demand Database |
| Actual Year Energy Load Data | February 8 | WECC | Summary of Estimated Loads and Resources<br>Information Summary<br>10-Year Coordinated Plan Summary |
| | | NERC | Electricity Supply and Demand Database |

The above data due dates represent the dates the data are due to the WECC staff from control areas. Since control areas operators are responsible for reporting data from non-control area operator entities within their respective areas, they will need to establish earlier dates for collecting coordinated future year data from those other entities. The list of Reports using data above is not all inclusive. Gathered data may be used in other NERC/WECC reports not listed.

# Attachment B: Interactive Excel Workbook

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# APPENDIX A-5-L

## Interactive Excel Workbook

This Excel Workbook is used for the L&R data reporting. The workbook contains historical L&R data which needs to be updated with new information and projections added. There are also several reports and charts that interactively show certain results related to the data submitted through the workbook, along with some data checking. The workbook is rather large and will work best if automatic calculation is turned off (see calculation section below).

Changes

For purposes of clarity and user functionality, in the 2006 Manual several of the workbook tab names were changed to more accurately reflect the purpose of the individual worksheets. For reference, the description and location of each tab name has not been altered. Additionally, in order to avoid confusion with the tab name changes, the previous worksheet tab name are listed below (in italic) along with the new tab name for each worksheet.

Workbook Structure

The following table is a summary of the worksheets in the workbook.

| Worksheet | Description |
|---|---|
| Main | Used to hold pertinent information about the represented area. |
| Status | Explains data requirements and provides feedback regarding the status of the input data. |
| gen_exist (*egdatu*) | Data input sheet for existing generation information. |
| gen_add (*gadatu*) | Data input sheet for generation additions information. |
| peak_data (*pkdatu*) | Data input sheet for the "peak" data, including peak loads, resources, outages, reserves, interchange, and transfers. |
| energy_data (*endatu*) | Data input sheet for energy load information. |
| Summary | This shows the results of the input data for loads, resources, outages, interchanges, and margins. |
| FAQ | Frequently asked questions. |
| WECC Status | Data input sheet for certain generation addition information. |
| Wind Factor | Data input sheet to collect information to calculate Wind Capacity Factor |
| x_growth (*XLdGth*) | A data checking form for load growth. |
| x_load_diff (*XLdDif*) | A data checking form for month to month load differences. |
| z_load_chart | A series of charts representing the reported loads and load |

| | |
|---|---|
| (*ZLoad*) | forecasts. |
| z_marg_chart (*ZMarg*) | A pair of charts showing resources versus loads and a chart comparing margins. |
| x_gen_comp (*XRdif*) | Tabular lists comparing resources from the generation data sheets {gen_exist} and {gen_add} to the peak data in sheet {peak_data}. |
| z_gen_chart_1 (*ZGad*) | Charts to present monthly generation changes and compare resource data as in z_gen_chart_2, but on a larger scale. |
| load_comp (*EnLoad*) | Comparison sheet of previous and current energy load data. |
| LoadOut | Comparison sheet of previous and current peak demands and outage data. |
| res_comp (*Res*) | Comparison sheet of previous and current resource data, including both committed and uncommitted units. The committed or uncommitted resource designation will be assigned by WECC Staff. |
| com_res_comp (*ResC*) | Comparison sheet of previous and current resource data, including only committed units. |
| z_gen_chart_2 (*ZGen*) | Two charts comparing the resource data from the generation data sheets {gen_exist} and {gen_add} to the peak data in sheet {peak_data}. |
| JP_Imp | Comparison sheet of previous and current joint plant imports. |
| JP_Exp | Comparison sheet of previous and current joint plant exports. |
| transfer_comp (*OthXF*) | Comparison sheet of previous and current firm imports and firm exports. |
| not listed | There are a few other worksheets in the workbook. These are hidden intentionally and should not be modified or disturbed. These are for WECC staff only. |

Data Reporting

The data input sheets (gen_exist, gen_add, peak_data, energy_data, and WECC Status) must be updated and checked as part of the L&R data submittal process. The descriptions of each of the data input sheets are presented below. See attachments C and D for detailed instructions. There should not be any blank rows in the final versions of the data input sheets. When adding, copying, or deleting rows, it is recommended that row-level editing be used (i.e., click on the row heading(s) to select).

The {gen_exist} existing generation worksheet is a detailed list of the generating units in the control area with commercial operation dates up to the end of the actual reporting year. Please check the data provided for accuracy and update as necessary per the instructions. If there are units missing from the list or new units, insert a new row and provide as much information as possible.

The {gen_add} generation additions worksheet is a detailed list of the generating units in the control area that represent increases or decreases in generating capacity during the actual year and in future years. This includes uprates and derates to existing plants, retirements, and new construction. Please update the provided list per the instructions and add rows as necessary to provide information about new additions, retirements, and other changes.

The {WECC Status} worksheet asks for specific information regarding generation additions reported in the {gen_add} worksheet. Please update the worksheet.

The {Wind Factor} worksheet asks for information about installed wind capacity and actual generation. This information will be used to calculate the monthly capacity factors for these wind resources.

The {peak_data} worksheet is a stand-alone listing of control area loads, resources, outages, reserves, interchange, and transfers.

The {energy_data} worksheet contains the actual and projected energy load data for the control area.

Data Checking

One of the goals of this workbook is to improve the accuracy of the data submittals. This should help to meet the NERC deadlines for forwarding the WECC information. The following data checks should be used to validate the data and locate data inconsistencies.

1. Data Input Sheets – the four data input worksheets (gen_exist, gen_add, peak_data, and energy_data) have a few data checks associated with certain columns. The headings of columns with bold headings will be highlighted in yellow if the data in the columns fails the designated data checks.
2. Load Growth – the {x_growth} worksheet lists the annual changes in peak demands and energy loads (% Growth rows) and highlights in yellow year-to-year load growth changes that exceed ± 1% (% Difference rows). An explanation is required for each of the highlighted '% Difference' load growths. The purpose of this data check is to identify the causes of unusual patterns in control area load forecasts which may be the result of the addition or deletion of major loads (e.g., startup or shutdown of a large industrial facility). Explanations regarding load changes from the prior actual year load to the current actual year load and from the current actual year load to the first future year forecast load should include references to the actual weather conditions experienced during the prior actual year and the current actual year. The charts in the {z_load_chart} worksheet can also be helpful for locating inconsistent and/or erroneous data.
3. Load Differences – the seasonal peak demand pattern is expected to repeat each year, with some growth from year to year. The differences in the monthly demands from year to year are presented in the {x_load_diff} worksheet. A chart in the {z_load_chart} worksheet shows the seasonal patterns from year to year.
4. Generation – a comparison of the cumulative resources is shown in the charts in the {z_gen_chart_2} worksheet. The charts are based on the generator lists in the {gen_exist},

{gen_add}, and {peak_data} input worksheets. The data from the {peak_data} worksheet should closely correlate with the data from the other two data worksheets. The second chart includes only committed units and is useful in finding problems with status codes related to unit commitment. The {x_gen_comp} worksheet presents a tabular comparison of the generation capacity and a comparison of monthly generation capacity differences. The charts in the {z_gen_chart_1} worksheet graphically show the changes in generation capacity, and provide another comparison of the resource data from the generator listings.

5. Load & Resource Summary – the {Summary} worksheet is similar to the margin reports in the "Summary of Estimated Loads and Resources" publication. This worksheet can help you find data problems or inconsistencies. The margin over firm load is an indication of a control area's ability to meet its load requirements, taking into account local resources, joint plant transfers, outages, firm transfers, firm purchases, and firm sales.

Calculation

The workbook requires up to several minutes to calculate. The calculation mode should be set to manual to avoid long calculation delays each time data is entered. Select Tools | Options | Calculation | Manual to set the calculation mode to manual if it isn't already.

With the calculation mode set to manual, the formulas are not calculated and cell results are not automatically updated. Pressing function key F9 will initiate a manual calculation of the entire workbook. Once the calculation is completed, the word 'Ready' will be displayed at the left of the status bar. The calculation progress display is generally not indicative of the actual progress. Typing or clicking with the mouse will often interrupt the calculation process, so it is important to be patient. If the word 'calculate' is displayed on the status bar, then a change has been made to the workbook that may or may not be reflected in the results.

It is recommended that users enter as much data as possible before initiating the calculation process. Note that the workbook is also calculated each time that it is saved, provided that this option is enabled.

Data Submission

After updating and checking the data, the workbook should be sent via e-mail to WECC. If the file is too large, it may be necessary to compress the file to a standard zip format.

The LRS procedures specify that the LRS Chair will contact the PCC representatives of reporting entities that have not submitted their data in accordance with the Attachment A schedule of data due dates. The LRS Chair may also contact the PCC representatives of reporting entities that have provided data that are incomplete or are not consistent with these reporting instructions.

Data Errors and need for Clarification

WECC Staff will contact a control area should the data checking process reveal a potential error, the need for clarification, and/or further explanation in the L&R data submitted for the control area within the control area's workbook. Should the data checking process reveal the need for

the control area to provide comments regarding the L&R workbook data (e.g., certain changes in growth rates exceed a set WECC criteria), WECC Staff will contact the affected control area.

Data Changing

As part of Data Errors and the need for Clarification (above), data changing will not be done without first notifying the control area affected by the change.

# Attachment C: Existing and Planned Generation Reporting Instructions

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## REPORTING INSTRUCTIONS FOR EXISTING GENERATION AND GENERATION ADDITIONS DATA

Control Area Operator Reporting Responsibilities

Each control area operator is responsible for submitting to the WECC Staff the existing generation and generation additions data and the Narrative Information Request document as needed for its entire control area/zone and is to include both its organization's information and information for all non-control area operator entities within the control area/zone. The control area operator is responsible for developing appropriate data collection procedures to ensure that updated information is obtained from the appropriate non-control area operator entities.

Non-control Area Operator Entities Reporting Responsibilities

Non-control area operator entities are responsible for responding to control area operator requests for generation information and for providing responses to the control area operator regarding the information requests made in the Narrative Information Request document incorporated into and provided with this Manual.

Data Reporting Process

Existing generation and generation additions worksheets are included in Attachment B of this Manual. The data are updated by changing the information presented in the worksheets for your control area. The changes should make the information current as of December 31, 2007 and, for control areas in the U.S., should be consistent with the data reported to the Department of Energy on the Energy Information Administration Form EIA-860 filing. However, the summer and/or winter capabilities reported in the worksheet may differ from the capabilities reported in the EIA-860 filing. For example, hydroelectric capabilities may differ due to differing assumptions for hydro conditions. If different summer and/or winter capabilities are reported in the EIA-860 filing compared to the WECC seasonal capability data, please note the reasons for the differences in comments below the plant entries.

Data for each unit that came into service during the past year are to be added in the same format as the existing entries. Please add the new entries immediately following the existing entries.

Comments should be included in the comment fields as requested. For example, for each independent power producer unit, provide the name of the unit owner(s), and for each inoperable unit state the unit is in deactivated shutdown, on cold standby, etc.

The combustion turbine portions and steam portions of combined cycle units may be reported separately. The rating of each should be equal to the rating that applies when the units are operated in a combined cycle configuration. Therefore, the sum of the ratings of each component should equal the rated output of the combined cycle unit. (An existing steam or combustion turbine unit, which in the future will be converted to a combined cycle unit, should not be reported as a combined cycle unit.)

# APPENDIX A-5-L

Worksheets for reporting changes in joint ownership and plant contingent capacity allocations are included in the L&R workbook. The worksheets will list the plant participants and their capacity allocations in megawatts and as percentages of total plant capacity.

Since the master database will be manually updated based on submitted worksheet revisions, please highlight, in green, all worksheet cells where changes are made.

Updated worksheets should be e-mailed to WECC staff: lbrown@wecc.biz, dick@wecc.biz, csmart@wecc.biz . Due dates are in Attachment A.

# APPENDIX A-5-L

## EXISTING GENERATION AND GENERATION ADDITIONS DATA FACILITY RECORD FORMAT

| Field Name | Field Contents | Explanation |
|---|---|---|
| EIAOC | EIA Organization Code | WECC Staff assigns these codes. |
| EIAP | EIA Plant Code | WECC Staff assigns these codes. |
| EIAU | EIA Generator Code | WECC Staff assigns these codes. |
| Zone | RS Assessment Zone | 4-character code (see Appendix F). |
| OrgCode | WECC Organization Code | 6-character code (see Appendix A). |
| OrgN | Organization Acronym | WECC Staff assigns these acronyms. |
| Power Plant Name | Power Plant Name | Maximum of 20 characters. |
| Unit | Unit Number | Maximum of 4 characters. |
| Power Plant Location | Power Plant Location | Maximum of 20 characters. The power plant name, unit number, and power plant location must not exceed 32 characters total. Use the state abbreviations in Appendix A. If words such as river, north, fork, etc., need to be abbreviated because of lack of space, use the abbreviations in Appendix A. |
| UE | EIA Unit Type | WECC Staff assigns these codes. |
| UW | WECC Unit Type | The following options are included in the workbook:<br><br>HY - Hydro - Conventional<br>PS - Hydro - Pumped Storage<br>ST - Steam Turbine - Non-Nuclear<br>NP - Steam Turbine - Nuclear<br>GT - Combustion Turbine<br>CA - Combined Cycle - Steam Portion<br>CT - Combined Cycle - Comb. Turbine Portion<br>CS - Combined Cycle - Single Shaft<br>CC - Combined Cycle - Total Unit (generation additions only)<br>GE - Geothermal<br>IC - Internal Combustion |

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| Field Name | Field Contents | Explanation |
|---|---|---|
| | | FC - Fuel Cell<br>BM - Biomass<br>PV - Solar Power - Photovoltaic<br>SP - Solar Power – Thermal<br>SO - Solar Power - Other<br>WT - Wind Power<br>CE - Compressed Air Energy Storage<br>NA - Not Available<br>OT - Other (Describe in Comment) |
| Name Pt | Nameplate Rating | Data are to be entered in kW. |
| SummerE | EIA Summer Capability | Data are to be entered in kW. If different from SummerW capability, provide an explanation following the plant entries. |
| SummerW | WECC Summer Capability | Data are to be entered in kW. The capability is to be the same as the information reported for the peak capability data on tab gen_exist. If different from SummerW capability, provide an explanation following the plant entries. Report zero for WECC summer capabilities of retired units and units that are out of service. Also report zero capabilities for operating units that are not included in the calculation of the hourly energy loads. |
| WinterE | EIA Winter Capability | Data are to be entered in kW. If different from WinterW capability, provide an explanation following the plant entries. |
| WinterW | WECC Winter Capability | Data are to be entered in kW. The capability is to be the same as the information reported for the peak capability data on tab gen_exist. If different from WinterW capability, provide an explanation following the plant entries. Report zero for WECC winter capabilities of retired units and units that are out of service. Also report zero capabilities for operating units that are not included in the calculation of the hourly energy loads. |

Refer to *WECC Criteria for Uniform Reporting of Generator Ratings* (Appendix C) for rating instructions for conventional technologies. For hydro-electric generation, base rating on median hydro conditions. For wind generation, compute ratings using the method described in the

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Narrative Information Request document provided with these Instructions. Please document the analyses used to compute these ratings in the manner described in the NIR.

For independent power producer generation entries, the summer and winter capabilities should be the expected net capacity available to the utility grid. You may note the nameplate rating in the comments.

| Field Name | Field Contents | Explanation |
|---|---|---|
| P F | Primary Fuel Code | The following options are included in the workbook:<br><br>BIT - Bituminous Coal<br>SUB - Sub-Bituminous Coal<br>LIG - Lignite Coal<br>WC - Waste Coal (Culm)<br>SC - Synthetic Coal-based fuel<br>PC - Petroleum Coke<br>DFO - Distillate Fuel Oil<br>JF - Jet Fuel<br>KER - Kerosene<br>RFO - Residual Fuel Oil<br>WO - Waste Oil<br>NG - Natural Gas<br>PG - Propane<br>BFG - Blast Furnace Gas<br>OG - Other Gas (coke oven, refinery etc.)<br>NUC - Nuclear<br>GEO - Geothermal Steam<br>WAT - Water - base ratings on median hydro conditions<br>AB - Agriculture Crop Byproducts<br>BLQ - Black Liquor<br>LFG - Landfill Gas<br>MSW - Municipal Solid Waste<br>OBL - Other Biomass Liquids<br>OBS - Other Biomass Solids<br>OBG - Other Biomass Gases (methane)<br>PUR - Purchased Steam<br>SLW - Sludge Waste<br>TDF - Tires<br>WDL - Wood or Wood Waste, Liquid<br>WDS - Wood or Wood Waste, Solid<br>SUN - Sun<br>WND - Wind<br>OT - Other (Describe in Comments)<br>NA - Not Available |

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If a unit can burn two or more different fuel types, report the type most likely to be burned as the primary fuel. Report the next fuel type most likely to be burned, based on expected annual energy predominance, as the alternate fuel.

| Field Name | Field Contents | Explanation |
|---|---|---|
| P1 | Primary Fuel Primary Transportation Method | The following options are included in the workbook:<br><br>CV - Conveyor<br>TK - Truck<br>PL - Pipeline<br>RR - Railroad<br>WA - Water Transportation<br>UN - Unknown At This Time<br>For any other methods, leave blank and clarify in the comments. Clarify CV, TK, PL, RR, WA, or UN, if necessary. |
| P2 | Primary Fuel Alternate Transportation Method | Use one of the options listed above under primary fuel primary transportation method. |
| A F | Alternate Fuel | Use one of the options listed above under primary fuel. Fuel used for start-up should not be reported as an alternate fuel. Note that the Narrative Information Request document contains explanation and asks for further information about this data item. |
| A1 | Alternate Fuel Primary Transportation Method | Use one of the options listed above under primary fuel primary transportation method. |
| A2 | Alternate Fuel Alternate Transportation Method | Use one of the options listed above under primary fuel primary transportation method. |
| SC | NERC Status Code | The following options are included in the workbook:<br><br>**Existing Generation Only**<br><br>OP - Operating or short-term outage<br>SB - Cold standby, 3-6 mo. to reactivate<br>OS - Out of service<br>RE - Retired |

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| Field Name | Field Contents | Explanation |
|---|---|---|
| | | **Generation Additions/Repowers Only** |
| | | P - Planned for installation but not under active construction |
| | | L - Regulatory approval pending but not under active construction (started site preparation) |
| | | T - Regulatory approval received but not under active construction |
| | | U - Under active construction, less than or equal to 50% complete (based on construction time to first electric date) |
| | | V - Under active construction, more than 50% complete (based on construction time to first electric date) |
| | | TS - Construction complete, but not yet in commercial operation (including low power testing of nuclear units) |
| | | A - Generator capability increased (rerated or relicensed) |
| | | D - Generator capability decreased (rerated or relicensed) |
| | | M - Generator to be put in deactivated shutdown status |
| | | RA - Previously retired or deactivated generator planned for reactivation |
| | | RT - Existing generator scheduled for retirement |
| | | FC - Existing generator planned for conversion to another fuel or energy source |
| | | RP - Proposed for life extension or repowering |
| | | CO - Change of ownership (including change of shares of jointly-owned units) |
| | | IP - Planned generator canceled or indefinitely postponed |
| | | OT - None of the above, explain in comments |
| O | NERC Ownership Code | U - Utility-owned unit |
| | | J - Utility-owned joint plant unit |
| | | I - Non-utility unit |

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| Field Name | Field Contents | Explanation |
|---|---|---|
| St | State Code | 2-digit state code (see Appendix E).<br>Use 88 for Mexico. Use 99 for Canada. |
| Cty | County Code | 3-digit county code (see Appendix E).<br>Organizations outside U.S. - leave blank. |
| ZIP plus4 | Zip Code | 9-digit postal zip code.<br>Organizations outside U.S. leave blank. |
| LRS SC | WECC Status Code | The following options are included in the workbook. Please select the status code that best reflects the current status of generation additions.<br><br>Note: Codes T, X, and Z are reported in a three digit code, 123, where the first digit represents the T status code, the second digit represents the X status code, and the third digit represents the Z status code. For example; a planned unit that has obtained the necessary building permits (T2), has a signed purchase power agreement (X4), and has obtained the necessary interconnection agreement (Z2) would be entered with the code 242. **Please provide additional information as requested in the Narrative Information Request document.**<br><br>**Generation Additions/Repowers Only**<br>T*x* - Regulatory Approval Received, where *x* equals:<br>1. IRP accepted/acknowledged<br>2. Building permit obtained<br>3. State siting license obtained<br>4. Air/water emission permits granted<br>5. Certificate of Public Convenience and Necessity obtained<br>6. Not applicable<br>7. All Regulatory approvals received<br>X*x* - Financial Commitment Complete, where *x* equals:<br>1. Municipal, PUD, or non-jurisdictional Co-op board approval<br>2. PUC rate approval<br>3. Funding commitment contract signed<br>4. Purchase power agreement signed |

| Field Name | Field Contents | Explanation |
|---|---|---|
| | | 5. Not applicable<br>6. All Financial Commitments finalized<br>*Zx* - Transmission/interconnection Available, where *x* equals:<br>1. Project deemed deliverable or transmission upgrades in progress<br>2. Interconnection agreement obtained<br>3. Transmission acquired<br>4. Pipeline interconnection agreement signed<br>5. Coal or other non-gas fuel supply contract signed<br>6. Not applicable<br>7. All Transmission/interconnection work completed<br>OT - Units not falling in above categories. **Provide listing and documentation in the Narrative Information Request document** |
| LRS O | WECC Ownership Code | U - IOU<br>M - Municipal, PUD<br>C - Co-op<br>J - Utility-owned joint plant unit<br>I - Non-utility unit |
| Cooling Water Source | Cooling Water Source | Up to 28-character description of cooling water source, if appropriate. Enter the name of the principal source from which cooling water for thermal-electric plants and water for generating power for hydroelectric plants is directly obtained. If more than one water source will be used, enter the name(s) of the other sources of water in comments. Enter 'municipality' if water is from a municipality. |
| C and U | Commitment Code | WECC Staff assigns these codes in coordination with LRS. If there is any special circumstance affecting the commitment status of a project, please provide an explanation in the Narrative Information Request document. |

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| Field Name | Field Contents | Explanation |
|---|---|---|
| O Yr | Existing generation only<br>Planned generation only | Year the unit entered service<br>Year unit was originally expected to be in service |
| OM | Existing generation only<br>Planned generation only | Month the unit entered service<br>Month unit was originally expected to be in service |
| OM | Existing generation only<br>Planned generation only | Month the unit entered service<br>Month unit was originally expected to be in service |
| RNYr | Existing generation only<br>Planned generation only | Year the unit was retired<br>Year unit is currently expected to be in service |
| MO | Existing generation only<br>Planned generation only | Month the unit was retired<br>Month unit is currently expected to be in service |
| MgCD | Multi-generation Code | 4-character designation that the unit's summer and winter capabilities of multiple units are reported under the first unit. |
| Comment 1<br>Comment 2<br>Comment 3<br>Comment 4<br>Comment 5<br>Comment 6<br>Comment 7<br>Comment 8 | Comments | Eight 30-character comment fields are provided. Comments are used for purposes such as providing explanations for OT unit type codes and fuel type codes, giving unit ownership information, explaining plant operating status, and documenting status of new generation, etc. |

# Attachment D: Peak Demands, Energy Loads, Resources, Resource Outages, Firm Transfers, and Planning Reserves Instructions

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# APPENDIX A-5-L

## INPUT GUIDE FOR
## PEAK DEMAND LOADS AND RESOURCES DATA

INTRODUCTION

Peak demand L&R information is collected to provide a data base which may be used to prepare power supply evaluations for the four WECC sub-regions report to NERC and for other sub-areas, including the zones used in the Supply Assessment Model (SAM) applied in the Power Supply Assessment (PSA). To accomplish this, the following data are required:

1) Loads – Both firm and non-firm, reported separately.

2) Resources data – Total installed capability of all wholly-owned utility generating facilities, the operator's share of jointly-owned utility generating facilities, and net capability available to the grid of internal (and radially connected) independent power producer (IPP) generation facilities are reported. Do not include generator output committed to serve station service requirements and do not include generator output committed to serve self-generation requirements (unless the reported load data also include the self-serve load).

3) Unavailable Capability – Total maintenance and outage data are reported. Independent power producer generation maintenance and outage data are reported unless the independent power producer generation resource data are net expected capabilities.

4) Transfer data – Utility firm and joint participation (including plant contingent or layoff sales) imports and exports, and external independent power producer generation imports and exports are reported.

5) Risk and Margin data – The largest risk data and planning reserves data must be reported.

A discussion about each of these required data types is presented starting on the next page. This discussion section is followed by a section that presents detailed information about the required data codes and data formats that must be used when creating the data response files.

Monthly peak demand L&R information are needed for the actual year and the following ten future years plus January, February, and March of the eleventh future year. All future year data should be reported under assumed adverse hydro. One data record may be submitted for each type of data to eliminate any ambiguity as to whether data entries are zero or the information was not submitted.

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## DATA TYPES, CODES, AND USE OF DATA IN THE L&R REPORT

LOAD DATA (Codes 1 and 2)

Peak demand load data are reported as firm and non-firm loads under data codes 1 and 2, respectively.

- Firm peak demand load data are to include the standby demand served at time of monthly control area peak demand during the actual year. For future years 1-10, Firm peak demand load data are to include the amount of standby demand that is expected to be served at time of monthly control area peak demand.
- Non-firm peak demand load data are to include interruptible demand and demand subject to Direct Control Load Management (refer to Appendix B, Glossary section, for the definition of this term) that was actually served at time of monthly control area peak demand during the actual year. For future years 1-10, the Non-firm peak demand load data are to include the amount of interruptible demand and demand subject to direct control load management that is expected to be served at time of monthly control area peak demand.
- Interruptible peak demand, demand subject to direct control load management, and direct control load management that is interrupted and therefore not served are separately reported under data code 2. Interruptible peak demands are designated by an 'I' in column C (T1) of the data record while direct control load management load actually served are designated by a 'L' in column C (T1) and unserved direct control load management are designated by a 'U' in column C (T1). Therefore, total direct control load management should be the sum of code 'L' and code 'U'. Do not report independent power producer self load in either the firm or non-firm load data.

For the actual year, the monthly sum of the firm peak demand, served demand subject to direct control load management, and interruptible peak demand must equal the total monthly metered peak demand. For future years, the monthly sums must equal the total monthly forecast peak demands.

Customer demand that can be curtailed in accordance with a contractual agreement (interruptible peak demand) is generally separately metered so actual year monthly interruptible peak demand data are usually available. However, direct control load management peak demand is generally not separately metered so estimated data may be required.

If future year direct control load management is forecast only for the peak summer (or winter) month, report the same load management for the other summer (winter) months. For the remaining months, please provide estimated data. If separate direct control load management data and contractually interruptible demand data are not available, report the combined data as interruptible load. However, separate data reporting is preferred.

The peak demand load forecasts should include such factors as economic, demographic, and customer trends; conservation, improvements in the efficiency of electrical energy use, and other changes in the end uses of electricity; and weather effects. **The peak demand load forecast should have a 50% probability of not being exceeded (expected peak demand). This load**

**forecast is commonly referred to as the 1-in-2 peak load forecast.** It is requested that you identify the weather probability assumed in creating the peak demand load forecast you submit used for obtaining historical weather data. Please provide this in the Narrative Information Request document.

The effects of utility-sponsored Demand-Side Management (DSM), (refer to Appendix B, Glossary section, for the definition of this term) programs are to be treated as follows:

- passive DSM (e.g., conservation and time of day metering) is to be treated as a reduction in firm peak demand, not as a capacity resource.
- direct control load management DSM is to be divided into two categories. One category represents the amount of direct control load management peak demand that the utility expects to be available for interruption at time of expected maximum peak demand. Because it was not used or is expected to be available but not used, it is to be reported as non-firm peak demand, not as a capacity resource. The other category of direct control load management represents the amount of direct control load management peak demand that the utility did interrupt for the historical year or expects to interrupt at time of expected maximum peak demand for the future years. This amount, if any, is not included as either a peak demand or as a capacity resource. It is reflected as reduced firm demand and is recorded using code 2.
- interruptible demand is treated similar to direct control load management DSM.

Individual systems should maintain documentation regarding the assumptions, methodologies, and the manner in which forecast uncertainties are addressed in their forecasts. This information would be helpful in understanding forecast discontinuities and deviations from actual-year peak demands.

The following example shows the treatment of a DSM program that provides for direct control of 20 MW of customer demand. Assume an expectation that 5 MW of the customer demand will be normally interrupted at time of monthly peak demand, leaving 15 MW of customer demand that may be interrupted under unusual or extreme circumstances.

| PEAK DEMAND - MEGAWATTS | JAN | FEB | MAR | APR | MAY |
|---|---|---|---|---|---|
| Total Controllable DSM | 20 | 20 | 20 | 20 | 20 |
| Amount normally interrupted | 5 | 5 | 5 | 5 | 5 |
| Amount normally served | 15 | 15 | 15 | 15 | 15 |

The firm and non-firm loads will be summed together as Total Load in the L&R Report. The 5 MW per month identified above as normally interrupted must be subtracted from total peak load.

| PEAK DEMAND - MEGAWATTS | JAN | FEB | MAR | APR | MAY |
|---|---|---|---|---|---|
| LOADS | | | | | |
| FIRM | 289 | 274 | 270 | 264 | 284 |
| Normally Served Interruptible /Load Mgt 15 | 15 | 15 | 15 | 15 | |
| TOTAL LOAD | 304 | 289 | 285 | 279 | 299 |

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RESOURCE DATA (Codes 3-13)

Resources are separately reported by generation type under data codes 3-13. The capability shown for all resources should be consistent with the capability reported in the existing generation and generation additions data. *If resource capability data for any resource type is only available in a manner that does not reflect the actual capability available during normal operating conditions at time of monthly peak, the resource capability can be reduced by reporting a set of monthly negative numbers that when summed with the reported resource capability will produce an adjusted capability that reflects the true capability expected under normal operating conditions at time of monthly peak.* Internal independent power producer resources should be reported as net of self-generation, maintenance, inoperable capability, and forced outages. The net internal independent power producer resources, therefore, report the net capability that is available to serve internal peak demand.

The resources will be summed together as Total Resources in the L & R Report.

| | | | | | | |
|---|---|---|---|---|---|---|
| RESOURCES - | HYDRO - CONVENTIONAL | 0 | 0 | 0 | 0 | 0 |
| | HYDRO - PUMPED STORAGE | 0 | 0 | 0 | 0 | 0 |
| | STEAM - COAL | 190 | 190 | 190 | 190 | 190 |
| | STEAM - OIL | 0 | 0 | 0 | 0 | 0 |
| | STEAM - GAS | 100 | 100 | 100 | 100 | 100 |
| | NUCLEAR | 60 | 60 | 60 | 60 | 60 |
| | COMBUSTION TURBINE | 100 | 100 | 100 | 100 | 100 |
| | COMBUSTION TURBINE | -10 | -20 | -20 | -10 | 0 |
| | COMBINED CYCLE | 0 | 0 | 0 | 0 | 0 |
| | GEOTHERMAL | 62 | 62 | 62 | 62 | 62 |
| | INTERNAL COMBUSTION | 0 | 0 | 0 | 0 | 0 |
| | WIND | 5 | 5 | 5 | 5 | 5 |
| | OTHER | 38 | 38 | 38 | 38 | 0 |
| | TOTAL RESOURCES | 545 | 535 | 535 | 545 | 517 |

Resources scheduled to come on-line in a future year may be designated as committed by WECC Staff based on status codes provided in the gen_add worksheet and in coordination with the LRS.

UNAVAILABLE CAPABILITY DATA (Codes 14-16, 31-34)

Actual year unavailable utility generating capability is reported under three data codes - 14, 15, 16 for Scheduled Maintenance, Inoperable Capability, and Forced Outages respectively. Forced Outages are reported as either Full or Partial. Full forced outages are reported under data code 16 with an 'F' in column F (S1) of the data record. Partial forced outages are separately reported under data code 16 with a 'P' in column F (S1) of the data record. Report independent power producer maintenance, inoperable and forced outage data unless these items are already accounted for in the net internal independent power producer resource data.

These outages will be summed together as Total Unavailable Capability in the L & R Report.

| | | | | | |
|---|---|---|---|---|---|
| FORCED OUTAGES | 10 | 0 | 0 | 25 | 0 |
| INOPERABLE CAPABILITY | 5 | 5 | 5 | 5 | 5 |
| SCHEDULED MAINTENANCE | 100 | 50 | 100 | 0 | 50 |
| TOTAL UNAVAILABLE CAPABILITY | 115 | 55 | 105 | 30 | 55 |

Future years 1-10 unavailable generating capability is reported under four data codes, namely 31-34. Scheduled Maintenance is reported as either Hydro or Non-Hydro under data codes 31 and 32. Inoperable Capability is also distinguished as to Hydro or Non-Hydro and is reported under data codes 33 and 34. The Hydro and Non-Hydro unavailable capability is reported separately for purposes of reliability calculations. For the L & R Report, however, the program combines them.

| | | | | | |
|---|---|---|---|---|---|
| INOPERABLE CAPABILITY | 5 | 5 | 5 | 5 | 5 |
| SCHEDULED MAINTENANCE | 40 | 0 | 0 | 100 | 60 |
| TOTAL UNAVAILABLE CAPABILITY | 45 | 5 | 5 | 105 | 65 |

In both the actual year and future years 1-10 the Total Unavailable Capability is then deducted from the Total Resources to obtain Net Resources.

| | | | | | | |
|---|---|---|---|---|---|---|
| RESOURCES - | HYDRO - CONVENTIONAL | 0 | 0 | 0 | 0 | 0 |
| | HYDRO - PUMPED STORAGE | 0 | 0 | 0 | 0 | 0 |
| | STEAM - COAL | 190 | 190 | 190 | 190 | 190 |
| | STEAM - OIL | 0 | 0 | 0 | 0 | 0 |
| | STEAM - GAS | 100 | 100 | 100 | 100 | 100 |
| | NUCLEAR | 60 | 60 | 60 | 60 | 60 |
| | COMBUSTION TURBINE | 100 | 100 | 100 | 100 | 100 |
| | COMBUSTION TURBINE | -10 | -20 | -20 | -10 | 0 |
| | COMBINED CYCLE | 0 | 0 | 0 | 0 | 0 |
| | GEOTHERMAL | 62 | 62 | 62 | 62 | 62 |
| | INTERNAL COMBUSTION | 0 | 0 | 0 | 0 | 0 |
| | WIND | 5 | 5 | 5 | 5 | 5 |
| | OTHER | 38 | 38 | 38 | 38 | 0 |
| | TOTAL RESOURCES | 545 | 535 | 535 | 545 | 517 |
| INOPERABLE CAPABILITY | | 5 | 5 | 5 | 5 | 5 |
| SCHEDULED MAINTENANCE | | 40 | 0 | 0 | 100 | 60 |
| TOTAL UNAVAILABLE CAPABILITY | | 45 | 5 | 5 | 105 | 65 |
| NET RESOURCES | | 500 | 530 | 530 | 440 | 452 |

TRANSFER DATA (Codes 50, 53-63)

For actual year and future year data collection, firm transfers are those transfers that occur or are anticipated during the 60 minute time of the peak demand for the month specified and for which there is a contract for capacity available at time of expected peak of the entity receiving the export. Therefore, all transfers relating to peak data are assumed to be firm, available during the peak hour of the month, with sufficient transmission capacity available on the peak hour of the month to complete the transfer.

Firm transfers include: transfers, sales, purchases, imports, exports, firm capacity transfers, contractual firm transfers, firm system transfers, full responsibility purchases, and full responsibility sales.

Transfers are reported as imports (negative) or exports (positive). Imports and exports are distinguished by the sign convention and either an 'I' (import) or 'E' (export) entered in column I (I/E) of the transfer data record. Firm system transfers are reported under code 50 and should specify that.

Joint participation transfers (includes joint plant transfers, utility plant contingent transfers, and external independent power producer generation transfers) are reported under transfer codes 53-63. The correct code for a joint participation transfer depends on the plant type. If the joint plant is a coal-fired facility the transfer code would be 55. (See the Joint Participation Plant Data and External IPP Data section, for more details on joint participation transfers.)

All transfers are reported between the sending and receiving organizations. No attempt is made to establish schedule paths or wheeling. The L&R data processing program requires that the future year transfers reported by the exporting entity and the importing entity agree in MW magnitude for each and all months. As such, a coordination effort is suggested prior to submitting transfer data to WECC.

Imports and exports will be summed separately and then combined to show a Net Exports/Imports in the L & R Report.

| | | | | | | |
|---|---|---|---|---|---|---|
| FIRM/JOINT PART. IMPORTS - | NWPP-W | -200 | -200 | -200 | -200 | -200 |
| TOTAL IMPORT | | -200 | -200 | -200 | -200 | -200 |
| FIRM/JOINT PART. EXPORTS - | RMPA | 50 | 50 | 50 | 50 | 50 |
| | NMPA | 50 | 50 | 50 | 50 | 50 |
| | AZ/S.NV | 50 | 50 | 50 | 50 | 50 |
| TOTAL EXPORT | | 150 | 150 | 150 | 150 | 150 |
| NET EXPORTS/IMPORTS | | -50 | -50 | -50 | -50 | -50 |

The program next lists the net of the Joint Participation Transfers. The net Joint Participation Transfers are subtracted from the Net Exports/Imports to obtain the Net Firm Transfers. (See the Joint Participation Plant Data and External IPP Data section, for details as to why this is done.)

| | | | | | |
|---|---|---|---|---|---|
| JOINT PARTICIPATION TRANSFERS | 50 | 50 | 50 | 50 | 50 |
| NET FIRM TRANSFERS | -100 | -100 | -100 | -100 | -100 |

The program next combines the Net Firm Transfers with the Net Resources to obtain the Net Resources and Net Transfers.

| | | | | | |
|---|---|---|---|---|---|
| NET FIRM TRANSFERS | -100 | -100 | -100 | -100 | -100 |
| NET RESOURCES AND NET TRANSFERS | 490 | 530 | 530 | 430 | 432 |

MARGINS

The program compares the Net Resources and Net Transfers to the firm load to obtain the Margin Over Firm Load in both MW and percent.

| | | | | | |
|---|---|---|---|---|---|
| NET RESOURCES AND NET TRANSFERS | 490 | 530 | 530 | 430 | 432 |
| MARGIN OVER FIRM LOAD - MW | 201 | 256 | 260 | 166 | 148 |
| MARGIN OVER FIRM LOAD - PERCENT | 69.6 | 93.4 | 96.2 | 62.9 | 52.1 |

RISK DATA (Codes 17 and 18)

All organizations are requested to submit largest risk (use data code 17) and second largest risk (use data code 18) data. The two largest risks should be identified in a written statement detailing the specifics of the risks and included in the narrative response to the Narrative Information Request document that parallels these L&R Instructions. Please note that risk is defined as the capacity reduction caused by outage of a generator (including independent power producer owned) or transmission line.

PROBABLISTIC RESOURCE PLANNING MARGIN (Code 19)

If your organization used a probabilistic resource planning process, you may report the resulting planning margin information (use data code 19). If you report probabilistically-determined planning reserves data, please also submit the following:

1) General description of the loss of load probability program.
2) Assumptions made.
3) Reserve margin by month for the future years 1-10 required that meet the minimum design performance specified. (Use data code 19.)

PLANNING RESERVE DATA (Code 20)

The control areas are asked to submit information that can provide a basis for WECC Staff and LRS to document conclusions regarding adequacy. One element of relevance is related to maintenance of targeted planning reserves. Individual utilities or planning groups are requested to submit their planning reserve (in megawatts), as determined by the utilities based on direction from their state regulators, local boards or any entity, which defines resource adequacy criteria for the utility footprint, at the time of their area's summer and winter peaks for each future year 1 through 10. The data are reported under data code 20 by month from January of the first future year through March of the tenth future year.

Please note that the planning reserves are to be based on your organization's planning requirements. Please provide supporting documentation for the reported data as specified by the Narrative Information Request document that parallels these L&R Instructions.

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## ACTUAL PEAK DEMAND LOADS AND RESOURCES
## DATA CODE DEFINITIONS
## 60-MINUTE PEAK DEMAND MW

(Actual Year - Report Monthly Data)
Column D of {peak_data} worksheet

ACTUAL HYDRO CONDITIONS

| DATA DESCRIPTION | DATA CODE | TRANSFER CODE |
|---|---|---|
| Loads - Firm (excluding station use) | 1 | Submit one data record for each import and export |
| Loads - Non-firm (interruptible and direct control load management normally served) | 2 | |
| Resources (Net Generation) | | |
| Hydro - Conventional & Pipeline Turbine | 3 | 53 |
| Hydro - Pumped Storage | 4 | 54 |
| Steam - Coal | 5 | 55 |
| Steam - Oil (oil only or dual fuel-oil primary) | 6 | 56 |
| Steam - Gas (gas only or dual fuel-gas primary) | 6 | 56 |
| Nuclear | 7 | 57 |
| Combustion Turbine ... (oil, gas, or dual fuel) | 8 | 58 |
| Combined Cycle..... (oil, gas, or dual fuel) | 9 | 59 |
| Geothermal | 10 | 60 |
| Internal Combustion.... (oil, gas, or dual fuel) | 11 | 61 |
| Wind | 12 | 62 |
| Other (including codes for Solar and Biomass) | 13 | 63 |

Some of the above resource types require alpha data codes to further classify the resource. The alpha codes used to accomplish this are described below:

**Combustion Turbine, Combined Cycle, and Internal Combustion**
Combustion Turbine, Combined Cycle, and Internal Combustion resources are separately reported by fuel type using the following conventions in column C (T1):
'D' for dual fuel capability,
'G' for gas-fired capability, or with an
'O' for oil-fired capability

**Steam-Oil**
Steam-Oil resources are separately reported by fuel type using the following conventions in column C (T1):
'E' for dual fuel capability - primarily oil-fired, or with an
'O' for oil-fired only capability

**Steam-Gas**
Steam-Gas resources are separately reported by fuel type using the following conventions in column C (T1):
'D' for dual fuel capability - primarily gas-fired, or with a
'G' for gas-fired only capability

**Other**
The Other resource type description is used to capture all other resource types. Specific resource type subcategories of Other can be designated using the following conventions in column C (T1):
'S' for Solar (all types) (see solar rating methodology in the Narrative Information Request)
'B' for Biomass (all types)
No alpha code is required for all other resource types within the Other category.

Scheduled Maintenance .....14
Inoperable Capability.....15
Forced Outages (Full and Partial).....16

Firm Transfers..... .....50

Report imports and exports separately. (Data values must be entered as minus (-) if transfer is an import, e.g., -150 and the letter 'I' must be entered in column 20 of the data record.).

# APPENDIX A-5-L

## ESTIMATED PEAK DEMAND LOADS AND RESOURCES DATA CODE DEFINITIONS

(Future Years 1-10 - Report Monthly Data)
(Also Report January, February, and March of Eleventh Future Year)

| | ADVERSE HYDRO CONDITIONS | |
|---|---|---|
| DATA DESCRIPTION | DATA CODE | TRANSFER CODE |
| Loads - Firm (excluding station use) | 1 | Submit one data record for each import and export |
| Loads - Non-firm (interruptible and direct control load management normally served) | 2 | |
| Resources (Net Generation) | | |
| Hydro - Conventional & Pipeline Turbine | 3 | 53 |
| Hydro - Pumped Storage | 4 | 54 |
| Steam - Coal | 5 | 55 |
| Steam - Oil (oil only or dual fuel-oil primary) | 6 | 56 |
| Steam - Gas (gas only or dual fuel-gas primary) | 6 | 56 |
| Nuclear | 7 | 57 |
| Combustion Turbine .. (oil, gas, or dual fuel) | 8 | 58 |
| Combined Cycle ..... (oil, gas, or dual fuel) | 9 | 59 |
| Geothermal | 10 | 60 |
| Internal Combustion .. (oil, gas, or dual fuel) | 11 | 61 |
| Wind (see wind rating methodology in the Narrative Information Request) | 12 | 62 |
| Other (including codes for Solar and Biomass) | 13 | 63 |

Some of the above resource types require alpha data codes to further classify the resource. The alpha codes used to accomplish this are described in the ACTUAL PEAK DEMAND LOADS AND RESOURCES section.

The Narrative Information Request document describes the methodology for designating resources with Alternate Fuel Capability and for determining the rating of Wind resources.

| | |
|---|---|
| Scheduled Maintenance | |
| Hydro (Include Hydro Pump Storage) | 31 |
| Non-Hydro | 32 |
| Inoperable Capability | |
| Hydro | 33 |
| Non-Hydro | 34 |
| Risk (The risk may be a generating unit, transmission line, or inter-connection. Submit a written statement detailing the specifics of risk - Unit name, Terminal names, etc.) | |
| Largest | 17 |
| Second Largest | 18 |

# APPENDIX A-5-L

Margin required by probabilistic resource planning criteria....19
Planning Reserve ..... 20
Firm Transfers..... 50

All transfers relating to peak data are assumed to be firm, available during the peak hour of the month, with sufficient transmission capacity available on the peak hour of the month to complete the transfer. Imports and exports should be reported separately.

# APPENDIX A-5-L

## ESTIMATED PEAK DEMAND LOADS AND RESOURCES CODING DATA RECORD FORMAT

(Actual Year and Future Years 1-10)
(Also Report January, February, and March of Eleventh Future Year)

| COLUMN | HEADING | DESCRIPTION |
|---|---|---|
| B | Year | Year |
| C | T1 | Data Code - Capability by fuel type: Oil only - 'O', Gas only - 'G', Dual fuel-gas primary - 'D', (for data codes 8, 58, 9, 59, 11, and 61 only).<br><br>For data codes 6 and 56 use 'O' for Oil only, 'G' for Gas only, 'D' for Dual fuel-gas primary fuel, 'E' for Dual fuel-oil primary fuel.<br><br>For data code 13 use 'S' for Solar (all types) and use 'B' for Biomass (all types).<br><br>Non-firm peak demand: Interruptible - 'I', Load Management - 'L' Load Management Unserved – 'U' (for data code 2 only). |
| D | Code | Data Code - Right Justified - Identifies type of data (see previous tables for actual and future year codes) |
| E | Org | WECC Control Areas Organization Codes (See Appendix A) |
| F | S1 | WECC Staff will assign a 'C' or a 'U' in this column to indicate whether the resource is a committed or uncommitted resource. Respondents should provide additional documentation along with the Narrative Information Request document response for any generation additions for which there is any aspects about its status that are not reflected by the generation additions codes.<br><br>For forced outages, data code 16 only, an 'F' indicates full forced outage data, while a 'P' indicates partial forced outage data.<br><br>For transfer codes 53 through 63, Resources (Net Generation), an '8' indicates that the values found in columns J through U, monthly energy, reflect joint plant or plant contingent peak capacity transfers associated with a committed resource. A '6' indicates that the values in columns J through U are associated with an uncommitted resource. Because these transfers have an equal and opposite value |

| COLUMNS | FORMAT | DESCRIPTION |
|---|---|---|
| | | associated with a counterparty, these values are not reduced for any reason. |
| | | A '9' indicates that the values in columns J through U are future year "expected peak capacity use factors" (expressed in thousandths) for joint plant or plant contingent transfers. |
| | | A WECC Control Area Organization Code should be specified in column G for all types of transfers and all "expected peak capacity use factor" data. |
| G | Org2 | WECC Control Areas Organization Codes (See appendix A). |
| H | N1 | Joint Ownership Plant ID (J.O. ID) |
| I | I/E | Transfer Export/Import Code: Export-'E', Import-'I' |
| J - U | Jan-Dec | Monthly Data Values |
| V | Comment | Comment |
| W | Annual | Enter monthly energy (GWh) for the actual year and first four future years. Only annual values are necessary for subsequent years. |

## JOINT PARTICIPATION PLANT DATA AND EXTERNAL IPP DATA

The joint participation peak demand transfers include joint plant transfers, plant contingent transfers (layoff sales/purchases), and external IPP generation transfers.

Column F of the transfer data record is used to flag joint participation transfers. An '8' in column F indicates a peak capacity transfer data, either import or export, associated with a jointly-owned plant (including plant contingent transfers). A '9' in column F indicates Expected Peak Capacity Use Factor (EPCUF) data. The product of the peak transfer and the EPCUF supplied by the importer is the amount that will be used in preparing the L&R Report. Generally, the EPCUF will be 1000 (100%) - in which case an EPCUF data record need not be submitted.

Joint participation transfers for Combustion Turbine, Combined Cycle, and Internal Combustion resources are coded by fuel type with a 'D' for dual fuel capability, a 'G' for gas-fired capability, or an 'O' for oil-fired capability in column C of the data record. Steam-Oil resources are coded by fuel type in column C of the data record with an 'E' for dual fuel capability - primarily oil fired or with an 'O' for oil-fired only capability. Steam-Gas resources are coded by fuel type in column C of the data record with a 'D' for dual fuel capability - primarily gas-fired or with a 'G' for gas-fired only capability.

The joint plant operator should report only its share of the plant under the appropriate data code (if a coal-fired plant, data code 5). The operator should report exports to each participant in the amount of their participation in MW under the appropriate transfer code (if a coal-fired plant, code 55). The operator reports only its share of the maintenance and forced outages under the appropriate codes.

Each participant must report its share of the joint plant as an import from the operator under the same transfer code and in the same magnitude as the export reported by the plant operating agent. The participant must report its share of the maintenance and forced outages under the proper codes. The program will then add the participant's share to the appropriate resource in the participant's report. This way joint participation plant capability shows up in the participant's report as a resource in the amount of its participation.

In addition to the MW import data records, the participant (importer) can provide EPCUF data records. The EPCUF allows the participant the option of delaying the import of capability from a joint plant if he feels that the operator's commercial operation date is too optimistic.

Joint participation shares are shown as resources in the participant's report in order to portray the capability of plants by ownership. Joint participation shares are reported as transfers to more accurately demonstrate the amount of capability that is being exchanged between areas. So that the joint participation shares will not be accounted for twice in calculating margins (as both a resource and a transfer), the program subtracts the net of the Joint Participation Transfers from the Net Exports/Imports. The Net Firm Transfers that result from the subtraction are combined with the Net Resources to yield the Net Resources and Net Transfers.

Transfers contingent on the output of a plant or unit are reported in the same manner as joint plant transfers. Therefore, to avoid double counting of capacity resources, the exporter of a plant contingent sale must not report the capacity in the amount of the transfer as a resource in its data, as this capacity will be added to the importer's resources under the appropriate resources category. Similarly, the importer of a plant contingent purchase must not report the capacity in the amount of the transfer as a resource in its data.

External independent power producer generation is to be reported by the purchaser as a transfer using an '8' in column F of the transfer data record. Since external independent power producer transfers are reported similar to the way joint plant transfers are reported, purchasers of external IPP capacity must not report the capacity in the amount of the purchase as resource. Doing so would cause double counting of the capacity.

The "Joint Ownership Plant Identification" code (J.O. ID) will be required whenever more than one joint ownership transfer with the same data code is represented between two organizations. The J.O. ID is a number from 0-9 used to tie the transfer of peak capability to the appropriate "expected peak capacity use factor." The participant's EPCUF data records must have J.O. ID numbers, which correspond to the appropriate transfer data records. An example of joint plant capacity transfer data reporting is given below:

EXAMPLES – FUTURE YEAR 2010

I. PEAK DEMAND TRANSFER

Organization A is buying 100 MW from organization B. This is a system transfer (not contingent on any one plant or unit) so transfer code 50 should be used.

```
A's Data Record - 10 50020101 030101 I -100 -100 -100 . . .
B's Data Record - 10 50030101 020101 E  100  100  100 . . .
```

II. JOINT PLANT DATA

Plant A - 500 MW (Coal Fired)

Participations

| | | |
|---|---|---|
| Operator X | - 50% | 250 MW |
| Participant Y | - 30% | 150 MW |
| Participant Z | - 20% | 100 MW |

```
X Reports:  10   5040101            250  250  250 . . .
            10 550401018040201 E  150  150  150 . . .
            10 550401018040202 E  100  100  100 . . .

Y Reports:  10 550402018040101 I -150 -150 -150 . . .

Z Reports:  10 550402028040101 I -100 -100 -100 . . .
```

## Energy Loads Instructions

Energy load data are reported as firm and non-firm loads under data codes 1, 2 in column D of worksheet {energy_data}. The energy load data are to be reported on the same basis as the peak demand load data (e.g., net of station service load and including transmission line losses).

The monthly actual energy loads and first, second, third, and fourth future year monthly forecast loads are reported in columns J through U. Annual forecast energy loads for future years five through 10 are reported in column W.

All energy load numbers are to be reported in gigawatt-hours.

# Attachment E: WECC Narrative Information Request

## Loads and Resources Data

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**APPENDIX A-5-L**

*Western Electricity Coordinating Council*

# WECC

## Narrative Information Request

## Loads and Resources Data Collection

WECC Staff

Loads and Resources Subcommittee

**September 2007**

# APPENDIX A-5-L

## Narrative Information Request

In order to improve the quality of Western Electricity Coordinating Council (WECC) Loads and Resources (L&R) assessments, narrative information is being requested on key issues. This is needed to increase consistency of multiple WECC L&R data/analyses and their application in transmission expansion planning, integrated resource planning and other related processes. This narrative request supplements elements of the *WECC Loads and Resources Data Collection Instruction Manual* ("Manual", "Instructions Manual", "the Manual") that need greater attention due to changing industry circumstances. The responsibility for providing this information resides with the control area operators, based on their own organization's information and responses provided to them by non-control area operator entities.

These Narrative Requirements are generally associated with variables already included within the Attachment B *Interactive Excel Workbook* ("Workbook") and the Attachment B instructions in the Manual. Please provide answers for each of the following ten items contained in this Word document. This response should be provided to WECC at the same time as the completed Workbook is provided. [3]

**1. Source and Vintage of Load Forecast and Generation Resource Information**

In order for WECC members and others to rely on WECC assessments, it is important to understand how WECC planning information compares to activities in other forums. In particular, there is a need for a basic description of the source and vintage of the load and generation resource information. Illustrative sources include: an integrated resource planning process, load and resource assessments to support a power plant application, load and resource assessments prepared to facilitate a request for offers to acquire long term resources through contract. In addition, it is requested that respondents identify whether the data provided are publicly available and if they have been approved by a regulatory or corporate entity.

Please provide this information for each major entity comprising the control area.

**2. Identification of Largest Generation and Transmission Risks**

The Instructions Manual includes a request to identify the largest single risk. This information should be provided separately for both generation and transmission.

Please describe the specifics of the single largest risk identified (e.g., unit name, terminal names) (Manual page 37, code 17) in the Workbook. Identify it as generation or transmission. Narrative information should be provided describing the complementary risk, either generation if transmission was included in the Workbook, or generation if transmission was included in the Workbook.

[3] Please do not include data or forecasts of the 2008-2010 peak load, energy demand or planned outages in this narrative request response document. Responses to the Narrative Information Request will not be confidential under provisions of the WECC L&R data disclosure policies, as described in the Introduction and Overview section of the Manual and in Appendix G of the Manual.

**3. Explanation of Planning Reserve Data**

Planning reserve data are requested in the Workbook (code 20) (Manual page 37); this narrative requests documentation of your response in the Workbook. For example, are the reserves computed from the application of a planning reserve margin applicable to the control area, or a subsidiary entity, or from some other source? Is the planning reserve margin specified by a regulatory authority?

Please provide a description that identifies what percent margin is required or specified; and the source and derivation of the planning reserve information reported.

**4. Explanation of Alternate Fuel Capability**

Improved information about alternate fuel capability is now necessary to initiate studies in response to possible North American Electric Reliability Council (NERC) requirements to better link electric system reliability to fuel supply interruptions. This requires: (1) up-to-date identification and review of current alternate fuel capability, and (2) a request for additional information about the nature of the backup provided by alternate fuels.

Please describe the alternate fuel capability of each facility in the traditional manner in the Workbook using the coding conventions in those Instructions (Manual page 23); provide a narrative description of the alternate fuel capability identified for each facility, including: (1) the minimum or maximum number of hours the facility can operate on a full load basis under current permitted emission levels, (2) the amount of alternate fuel stored on-site at the facility or the amount of fuel available through the identified transportation method, (3) the minimum time required to switch from the primary fuel to the alternate fuel, and (4) the maximum number of hours the facility can operate on a continual full load basis using the alternate fuel.

**5. Wind and Solar Capacity Ratings**

The Instructions Manual requests identification of capabilities of all generation (Manual pages 38-41) but does not presently include a specific methodology for determining the capability de-rates of wind and other renewable resource generation. For the 2007-08 reporting cycle, the capacity reporting for Wind and Solar renewable resources will be reported using the following methodology.

1. For each resource type, provide the 3 year average Installed Capability of all Wind, Solar PV, Solar Thermal and Solar Other generation within your control area at time of peak for each month. If 3 years of data are not available, use the average of the most recent 2 years or, the most recent year if only one year's data is available. If no actual data is available (such as for new plants), use the nameplate capacity. Use the appropriate resource code for each type reported.
2. 
   a. For each resource type, calculate the average of the actual portfolio production over the most recent 3 year period at time of control area peak demand for each month. If 3 years of data are not available, use the average of most recent 2 years or, the most

recent year of production data, at time of control area peak demand. If no actual production data is available (such as for new plants), use the predicted production at time of control area peak demand.

b. Subtract the amount calculated in 2.a. from the amount in 1. and report the remaining amount as a NEGATIVE number for each month using the appropriate resource code for each type. This number represents the capacity derate associated with each resource type.

This methodology will allow the Load and Resources Subcommittee (LRS) to estimate the average Net Dependable Capability of Wind and Solar renewable resources by type as well as the total amount of capacity to be expected from each of these resource types at time of peak for each control area.

**6. Interruptible Tariff Loads and Controllable Demand Response**

The L&R Instructions require identification of non-firm loads and controllable demand response capabilities not assumed to be activated at times of monthly peaks (Manual page 32). Please describe the monthly non-firm load that is a result of interruptible tariffs or other contractual arrangements with specific customers.

Please identify controllable demand response capabilities for each month. Identify the program name and its expected load reduction capability by month assuming the curtailment restrictions embodied in applicable tariff and/or contractual agreements with end-use customers.

**7. Weather Assumptions Associated with Load Forecast**

The peak demand load forecast requested in the Instructions is specified as the 1-in-2 forecast (Manual page 32). In order to better understand the load impacts of severe weather, we request that you identify the weather conditions (e.g., 1 in 2, 1 in 5 etc.) assumed in creating the submitted forecast. It should be noted that a forecast other than a 1-in-2 forecast will be rejected as invalid data.

**8. Wind Capacity Factors**

Improved information about renewable resources, especially wind, is necessary to better link electric system reliability with intermittent resources. This requires: (1) a better understanding of wind capacity factors during peak hours, and (2) an improved knowledge of installed wind capacity.

In order to improve the WECC understanding of wind capacity factors a new worksheet, Wind Factor, has been added to the Workbook. Please supply: (1) the actual wind generation on the peak hour for each month of 2006, (2) the nameplate capacity of installed wind resources during the monthly peaks of 2006, and (3) the peak demand for each month of 2006. WECC staff will use this data to calculate the monthly wind capacity factor.

Also, WECC would like to know the simultaneous wind capacity factors for the entire Interconnection under an extreme temperature condition. Therefore, please provide the actual wind generation, nameplate capacity, and demand information for July 24, 2006. For entities in the Pacific Time zone, please provide this information for Hour Ending 1600, and for entities in the Mountain Time zone, provide this information for Hour Ending 1700.

**9. Committed versus Uncommitted Designations for Resources**

The Workbook includes a designation of committed "C" and uncommitted "U" for each resource based on previous submissions and WECC Staff evaluations. These designations should be carefully reviewed. This information has been under considerable scrutiny in recent years as project status is more volatile and more entities are reviewing WECC products or the underlying generation database.

In order to improve the WECC characterization of likely resource availability, a separate set of WECC status codes are included in the Instructions (Manual pages 26-27). Please supply the requested information below for each resource you report on the WECC Status worksheet, identifying all of its characteristics as of January 1, 2007. LRS will identify resources most likely to be available based on your responses to the WECC status codes.

Please provide any additional information you consider relevant if the coding conventions identified in the L&R Instructions and Table 1 do not satisfy the circumstances for resources you are reporting.

TABLE 1: Characterization of Status of Identified Generation Additions or Repowers

Control Area Code
Unit ID
Unit Name
Unit Location
Regulatory Status
1. IRP accepted/acknowledged
2. Building permit obtained
3. State siting license obtained
4. Air/water emission permits granted
5. Certificate of Public Convenience and Necessity obtained
6. Not applicable
7. All regulatory approvals received

Financial Commitment Status
1. Municipal, PUD, or non-jurisdictional Co-op board approval
2. PUC rate approval
3. Funding commitment contract signed
4. Purchase power agreement signed
5. Not applicable
6. All financial commitments finalized

Transmission/Fuel Infrastructure Status
1. Project deemed deliverable or transmission upgrades in progress
2. Interconnection agreement obtained

3. Transmission acquired
4. Pipeline interconnection agreement signed
5. Coal or other non-gas fuel supply contract signed
6. Not applicable
7. All transmission/interconnection work completed

Year Projected Operational

**10. Description of Hydro Reporting Methodologies**

Definitions of hydro conditions contained in the Instructions (Manual Appendix B page 71) allow for wide variation in what may be reported by different entities with varying hydro conditions. To improve understanding of how hydro generation is evaluated both for median and adverse hydro conditions, please provide the following information, if applicable:

- What type of hydro plant(s) are located in the control area—run-of-river, storage, etc?
- Is the hydro capacity provided based on a static head, or on a weighted average head in cases where reservoir head varies during the months of the year and possibly with water condition?
- For situations in which hydro capacity and energy vary over the year or by water condition, how are these values determined? In particular, describe how hydro generation based on median and adverse hydro conditions is calculated:
    - Are water-power operation studies performed?
    - If so, are water inflows based on historical, modified historical, or stochastic water conditions? For what period of record?
    - Do median and adverse hydro conditions reference a particular historical water condition, percent exceedence water or generation condition or some other condition?
- If your utility, or utilities in your control area, prepare(s) Integrated Resource Plans, what assumptions are used for hydro generation in those plans?

# APPENDIX A: WECC CONTROL AREAS & ABBREVIATIONS

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# APPENDIX A-5-L

## WECC CONTROL AREAS

| | Control Area Organization Code |
|---|---|
| Northwest Power Pool Area | |
| Alberta Electric System Operator | 010407 |
| Avista Corp. | 010116 |
| Bonneville Power Administration – Transmission | 010102 |
| British Columbia Transmission Company | 010301 |
| Chelan County Public Utility District | 010104 |
| Douglas County Public Utility District | 010106 |
| Grant County Public Utility District | 010108 |
| Idaho Power Company | 010201 |
| NorthWestern Energy | 010203 |
| PacifiCorp – East | 010205 |
| PacifiCorp – West | 010110 |
| Portland General Electric Company | 010112 |
| Puget Sound Energy | 010113 |
| Seattle Department of Lighting | 010114 |
| Sierra Pacific Power Company | 010211 |
| Tacoma Power | 010115 |
| Western Area Power Administration, Upper Great Plains – West | 010210 |
| Rocky Mountain Power Area | |
| Public Service Company of Colorado | 020104 |
| Western Area Power Administration, Colorado-Missouri Region | 020113 |
| Arizona-New Mexico-Southern Nevada Power Area | |
| Arizona Public Service Company | 030202 |
| Duke – Arlington Valley | 030214 |
| El Paso Electric Company | 030101 |
| Gila River Maricopa Arizona | 030215 |
| Harquahala Generator Maricopa Arizona | 030216 |
| Imperial Irrigation District | 030206 |
| Nevada Power Company | 030207 |
| Public Service Company of New Mexico | 030105 |
| Salt River Project | 030203 |
| Tucson Electric Power Company | 030205 |
| Western Area Power Administration, Lower Colorado Region | 030213 |
| California-Mexico Power Area | |
| California Independent System Operator | 040105 |
| Comision Federal de Electricidad | 040301 |
| Los Angeles Department of Water and Power | 040102 |
| Sacramento Municipal Utility District | 040106 |
| Turlock Irrigation District | 040107 |

Appendix D presents a detailed list of electric utility organizations within each of the above control areas.

# APPENDIX A-5-L

## STATE ABBREVIATIONS

| ABBREVIATION | STATE (PROVINCE) |
|---|---|
| AB | Alberta |
| AZ | Arizona |
| BC | British Columbia |
| CA | California |
| CO | Colorado |
| ID | Idaho |
| KS | Kansas |
| MT | Montana |
| NE | Nebraska |
| ND | North Dakota |
| NM | New Mexico |
| NV | Nevada |
| OK | Oklahoma |
| OR | Oregon |
| SD | South Dakota |
| TX | Texas |
| UT | Utah |
| WA | Washington |
| WY | Wyoming |

## MISCELLANEOUS ABBREVIATIONS

(Use only when limited by space)

| | |
|---|---|
| R | River |
| N | North |
| S | South |
| F | Fork |
| CR | Creek |
| MF | Middle Fork |
| SF | South Fork |
| SPGS | Springs |
| CT | Combustion Turbine |
| CC | Combined Cycle |

# APPENDIX B: CRITERIA, KEY DEFINITIONS, AND TERMINOLOGY CONVENTION FOR CONTROL AREA REPORTING TO WECC

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## CRITERIA, KEY DEFINITIONS, AND TERMINOLOGY CONVENTION FOR CONTROL AREA REPORTING TO WECC

(For Other Definitions – See Enclosed Glossary)

### PEAK DEMAND LOADS AND RESOURCES

| | | |
|---|---|---|
| Demand Interval | – | 60 Minutes. |
| Firm Transfers | – | The firm (contracted for) transfers at the time of the peak demand for the month specified. (Include transfers associated with joint ownership generation.) Firm transfers include: transfers, sales, purchases, imports, exports, firm capacity transfers, contractual firm transfers, firm system transfers, full responsibility purchases, and full responsibility sales. Report imports and exports separately. Do not combine them to form a net firm transfer. |
| Forced Outages | – | For the past year, report the coincident sum of capabilities (net generation) that were out-of-service due to forced outages (full and partial) at the time of the peak demand for the month specified. |
| Inoperable Capability | – | The coincident sum of capabilities (net generation) that could not be operated for reasons such as lack of fuel availability, legal restrictions, lack of manpower, etc., at the time of the peak demand for the month specified. Inoperable capability does not include scheduled maintenance or forced outages. |
| Load | – | The maximum 60-minute coincident peak demand (including transmission system losses and standby demand) expected during the month specified. (Do not include station use, self load, or pumped storage pumping.) |
| Maintenance | – | Transfers resulting from participation in joint ownership projects are not to be reduced for maintenance. However, the operating agent will provide all participants with a maintenance schedule for the project, which the participants should use as a guide in preparing their own maintenance schedules. Do not report maintenance for independent power producer resources. |
| Sign Convention | – | Imports (firm transfers into an area) carry a minus (-) sign. |
| Resources | – | Net generation based on capabilities consistent with the *WECC Criteria for Uniform Reporting of Generator Ratings* (Appendix C). Do not reduce utility resources for scheduled maintenance, inoperable capability, or forced outages. |

| | | |
|---|---|---|
| | | Independent power producer capabilities are to be reduced for scheduled maintenance, inoperable capability, and forced outages only if non-aggregated data are not available. |
| Resources - Joint Ownership | – | For the actual year and the future years 1-10, the operating agent should report its share only. Participant's shares are reported as transfers. |
| Resources - Other | – | Include only resources for which the unit type has not been assigned a data code (i.e., Fuel Cell) or the unit type and fuel have not been established. |
| Scheduled Maintenance | – | The coincident sum of capabilities (net generation) that are down for scheduled maintenance (including inspection) at the time of the peak load for the month specified. |
| Units of Measurement | – | Megawatts (MW). |

**ENERGY LOADS**

| | | |
|---|---|---|
| Load | – | The gigawatt-hours of load (including transmission system losses and standby demand) estimated for the period (month or year) reported. It does not include energy required for pumping of pumped storage generating plants, self load, or station use. |

**EXISTING GENERATING CAPABILITY and SIGNIFICANT ADDITIONS AND CHANGES**

| | | |
|---|---|---|
| Hydro Units | – | Report utility net generation based on capabilities consistent with the *WECC Criteria for Uniform Reporting of Generator Ratings* at the time of the summer and winter system peak loads under Median Hydro Conditions. For independent power producer entries, the summer and winter capabilities should be the expected net capability available to the utility grid. |
| Joint Ownership Plants | – | The control area in which the plant is located reports the entire plant capability. |
| Pumped Storage Capability | – | Report net generating capability consistent with the *WECC Criteria for Uniform Reporting of Generator Ratings* as described for Hydro Turbo-Generator Capability at the time of the summer and winter system peak loads under Median Hydro Conditions. Do not reduce unit capability to reflect pumping requirements, scheduled maintenance, inoperable capability, or forced outage. |

# APPENDIX A-5-L

| | | |
|---|---|---|
| Primary Fuel | – | If a unit can burn more than one type of fuel, report the fuel most likely to be burned as the primary fuel. |
| Thermal Units | – | Report utility net generation based on capabilities consistent with the *WECC Criteria for Uniform Reporting of Generator Ratings* at time of the summer and winter system peak loads. For independent power producer entries, the summer and winter capabilities should be the expected net capability available to the utility grid. |
| Multiple Units | – | Multiple generators operated together (i.e., cross-compound) should be reported with one generator ID. Generators with a nameplate capacity less than 5,000 kilowatts may be grouped by like prime mover and energy source (regardless of plant) provided that the aggregate nameplate capacity of any group does not exceed 100,000 kilowatts. If grouped, report for each group the prime mover, energy source(s), aggregate nameplate capacity, and aggregate summer and winter capabilities. In the "Comments", indicate the number of generators included in each group of generators. |
| Nameplate Capacity | – | Report the maximum nameplate capacity of the generator in kilowatts. If the nameplate capacity expressed in kilovoltamperes, convert to kilowatts by multiplying the power factor by the kilovoltamperes. If more than one capacity appears on the nameplate, report the highest capacity. |
| Commercial Operation Date | – | Report the month and year that control of the generator was turned over to the dispatcher. |

# APPENDIX C: GLOSSARY FOR WECC LOADS AND RESOURCES DATA COLLECTION

## GLOSSARY FOR WECC LOADS AND RESOURCES DATA COLLECTION

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|---|---|
| ACTIVE CONSTRUCTION | Active construction includes personnel consistently onsite, payroll met, building materials delivery ongoing, turbine or other major items on order, etc. |
| AVOIDED COST | The cost an electric utility would otherwise incur to generate power if it did not purchase electricity from another source. |
| BIOMASS | Any organic material not derived from conventional fossil fuels. Examples are animal waste, agricultural or forest by-products, and municipal refuse. |
| CAPABILITY | The maximum load which a generator, turbine, transmission circuit, apparatus, stations, or system can supply under specified conditions for a given time interval, without exceeding approved limits of temperature and stress. |
| Net | The gross capacity of a generating unit as measured at the generator terminals less the power required for the auxiliary equipment (such as fan motors, pump motors, and other station service equipment essential to operate the unit). |
| CAPACITY | Synonymous with capability. |
| CAPACITY WITH FULL RESERVE | The highest (in availability) form of capacity transaction. The system is obligated to deliver power and energy at a specified degree of reliability. The selling system must purchase power or take other appropriate actions before curtailing the transactions. |
| CAPACITY WITHOUT RESERVE | A transaction in which the capacity is supplied when available from the aggregate of generating units of the seller. The seller does not have to deliver power and energy whenever certain system conditions exist that would impose undue hardship on the seller. |
| CONSERVATION | Implementation of measures that decrease energy consumption of targeted end uses resulting in beneficial load shape changes, often by encouraging the use of more efficient appliances and equipment. |
| DEMAND | The rate at which electric energy is required by a system, part of a system, or a piece of equipment expressed in megawatts, megavolt-amperes, or other suitable unit at a given instant or averaged over any designated period of time. |

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| Average | The demand on, or the power output of, an electric system or any of its parts over any interval of time, as determined by dividing the total number of kilowatt-hours by the number of units of time in the interval. |
| Coincident | Two or more demands that occur in the same demand interval. |
| Firm | The maximum 60-minutes coincident load for the month specified. It includes transmission system losses and standby demand, and excludes station service, self load, load management, and interruptible loads. |
| Internal | The maximum integrated clock hour sum of the demands of all customers which a system serves, plus the losses incidental to that service. Internal Demand is quantified by summing the metered (net) outputs of all generators within the system, plus the metered line flows into the system, minus the metered line flows out of the system. The demand of station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to operation of the generating units) is not included. Internal Demand includes adjustments (i.e., is reduced to reflect the effects of conservation, etc.) for utility indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates. It is not reduced by utility Direct Control Load Management or Interruptible Demand. |
| Interval | The period of time during which the electric energy flow is averaged in determining demand; such as 60-minute, 30-minute, 15-minute, or instantaneous. |
| Maximum (Peak) | The greatest of a particular type of demand occurring within a specified period. |
| Standby | Standby Demand is demand that may be served, in accordance with contractual arrangements, to provide power and energy to a customer (often to a cogenerating industrial customer) as a second source or backup for outage of the customer's generation. Standby power is intended to be used infrequently by any given customer. Probability considerations should be applied to determine the amount of standby demand included in firm load. |

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| DEMAND-SIDE MANAGEMENT (DSM) | The term for all activities or programs undertaken by an electric system or its customers to influence the amount and timing of electricity use. Included in DSM are the planning, |

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| | implementation, and monitoring of utility activities that are designed to influence consumer use of electricity in ways that will produce desired changes in a utility's load shape, such as, among other things, direct load control, interruptible load and conservation. |
| ELECTRIC DEMAND | The instantaneous electric requirement of a power system, usually expressed in units such as megawatts (MW) or kilowatts (kW). |
| ENERGY | Electric energy is usually measured in gigawatt-hours. |
| FUEL CELL | A device in which a chemical process is used to convert a fuel directly into electricity. |
| FULL RESPONSIBILITY PURCHASE | A Full Responsibility capacity purchase results when the seller is contractually obligated to deliver power and energy to the purchaser with the same degree of reliability as provided to the seller's own native load (customers). |
| FULL RESPONSIBILITY SALE | A Full Responsibility capacity sale results when the seller is contractually obligated to deliver power and energy to the purchaser with the same degree of reliability as provided to the seller's own native load (customers). In published reports this is the sum of firm exports and planned sales. |
| GENERATION | The act or process of producing electric energy from other forms of energy; also the amount of energy so produced. |
| Gross Generation | The total amount of electric energy produced by a generating station or stations, measured at the generator terminals. |
| Hydro | A term used to identify a type of electric generating station, capacity, or capability, or output in which the source of energy for the prime mover is falling water. |
| Net Generation | Gross generation less station use. |
| Independent Power Producer Generation (IPP) | A general term embracing facilities named in the Public Utility Regulatory Policies Act (cogenerators and small power producers) and any other independent power producer generating facilities connected to the utility system (excluding self generation). External IPP resources are those located outside of the service area of the utility purchasing the generation. A wheeling utility provides transmission service for the external IPP. Internal IPP resources are those which are located within the service area of the utility purchasing the |

generation or are radially connected to the purchasing utility and do not require wheeling by another utility.

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| Pumped Storage Plant | A power plant utilizing an arrangement whereby electric energy is generated for peak load use by utilizing water pumped into a storage reservoir usually during off-peak periods. A pumped storage plant may also be used to provide reserve generating capacity. |
| Station Use | Energy used in a generating plant as necessary in the production of electricity. It includes all energy consumed for plant light, power, and auxiliaries regardless of whether such energy is produced at the plant or comes from another source. |
| Thermal | A term used to identify a type of electric generating station, capacity, or capability, or output in which the source of energy for the prime mover is heat. |
| Cogeneration | Equipment used to produce electric energy and forms of useful thermal energy, such as heat or steam, used for industrial, commercial, heating or cooling purposes, through sequential use of energy. Combined Cycle generation is not considered cogeneration. |

LOAD — The amount of electric power delivered or required at any specified point or points on a system. Load originates primarily at the power consuming equipment of the customers. See DEMAND.

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| Firm Load | Electric power load (including standby demand) intended to be served at all times during the period covered by a commitment, even under adverse conditions. |
| Interruptible Demand (Load) | Electric power load (including load management), which may be curtailed at the supplier's discretion, or in accordance with a contractual agreement. In some instances, the demand reduction may be affected by direct action of the system operator (remote tripping) after notice to the customer in accordance with contractual provisions. For example, demands that can be interrupted to fulfill planning or operating reserve requirements normally should be reported as interruptible demand. |
| Direct Control Load Management | A procedure in which customer demand can be controlled through the direct action of the system operator through actual interruption of power supply to individual appliances or equipment on the customer's premises. This type of control usually reduces the demand of residential customers. Direct |

Control Load Management excludes Interruptible Load and other load management effects.

Standby Power — Power used to serve customer demand in accordance with contractual arrangements to provide power and energy to a customer (often for an industrial customer having his own generation) as a second source or backup for the outage of the primary source. Standby Power is intended to be used infrequently by any given customer.

MARGIN — The differences between capacity and peak demand. Margin is usually expressed in megawatts.

Capacity — The differences between capacity and firm peak demand divided by capacity expressed as a percentage. The capacity margin (CM) equals the reserve margin (RM) divided by one plus the reserve margin or CM = RM / (1 + RM).

Reserve — The difference between capacity and firm peak demand divided by firm peak demand expressed as a percentage. The reserve margin (RM) equals the capacity margin (CM) divided by one minus the capacity margin or RM = CM / (1 - CM).

NET DEPENDABLE CAPABILITY (NET CAPABILITY) — The maximum load which a generating unit, power plant, or system can supply under specified conditions for a given time interval, without exceeding approved limits of temperature and stress. When used in reference to a system or plant, capability includes all generating units except those whose sole function is to supply emergency power for startup and shutdown. It includes the capability of units that may be temporarily inoperable because of maintenance, forced outage, or other reasons, or only operable at less than full output. It excludes power required for plant operation.

NET ENERGY — The electric energy requirements of a system. It is defined as system net generation plus energy received from others less energy delivered to others. It includes system losses but excludes energy required for "pumping up" pumped storage plants.

NON-COINCIDENT PEAK DEMAND — The sum of individual systems' Peak Demands, regardless of when they occur. Non-coincident Peak Demand will always be greater than or equal to the Coincident Peak Demand.

OUTAGE — The period during which a generating unit, transmission line, or other facility is out-of-service.

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| Forced Outage | The shutting down of a generating unit, transmission line, or other facility, for emergency reasons. |
| Scheduled Outage | The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule. |
| POWER POOL | Two or more interconnected power systems operated as a system and pooling their resources to supply the power and energy requirements of the systems in a reliable and economical manner. |
| PREVIOUS YEAR | The calendar year immediately preceding the reporting year. For a report filed April 1, 2006, the previous year is 2005. |
| PRIOR ACTUAL YEAR | The calendar year immediately preceding the PREVIOUS YEAR. For a report filed April 1, 2006, the prior actual year is 2004. |
| PURPA | The Public Utility Regulatory Policies Act enacted in November 1978. |
| QUALIFYING FACILITY (QF) | An independent power producer cogeneration or small power production resource that meets PURPA standards including: Less than 50 percent utility ownership; less than 80 MW capacity; and, if a small power producer, uses geothermal, biomass, waste, or renewable resources to produce electric power with specific limits on the amount of coal, oil, or natural gas that may be used for electric power production. |
| REGIONAL COUNCIL | One of nine electric reliability councils that form the North American Electric Reliability Council (NERC). (NERC was formed in 1968 by the electric utility industry to promote the reliability and adequacy of the bulk power supply in the electric utility systems of North America.) |
| REPORTING YEAR | The calendar year in which the EIA-411 Report is filed. For instance, 2006 is the reporting year for a report filed April 1, 2006. |
| RESERVE | Synonymous with Margin. |
| SELF GENERATION | Independent power producer generation that is not available to a utility system as it is used to serve the independent power producer's own load. Self generation is generally used to serve load that would otherwise be served by a utility. A utility may or may not provide standby service as a backup for the outage of an independent power producer's self generation. |

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| SELF LOAD | Independent power producer load that is served directly from independent power producer generation that is not contractually available to a utility system to serve other load (i.e., served by self generation). Standby demand may result from a utility's contractual commitment to provide second source or standby capacity to a customer with self load. |
| SUMMER PEAK PERIOD | The summer peak period begins on June 1 and runs through September 30. |
| SYSTEM | The physically connected generation, transmission, distribution and other facilities operated as an integral unit under one control, management or operating supervision, often referred to as "electric system," "electric power system" or "power system." |
| TRANSFER | The transfer of electrical energy across a point or points of interconnection during a stated period. |
| UNIT POWER | Power from one or more specific generating units. Unit Power purchases and sales are forms of capacity transactions without full reserve. Capacity is sold from one or more specific units for a certain period of time. Delivery of power and energy is contingent on the unit being available. |
| VOLTAGE REDUCTION | A means to reduce the demand on a utility by lowering the voltage. Usually performed on the distribution or subtransmission system. |
| WATER CONDITIONS | |
| Adverse Hydro | Runoff and storage regulation which reflect operation under lowest-quartile stream flow conditions. The lowest-quartile condition may be as severe as the most critical streamflow conditions that have occurred during a specified period, usually the period of historical record. |
| Median Hydro | Runoff and storage regulation which reflect operation under normal stream flows for which there are an equal number of greater and less flow occurrences during a specified period, usually the period of historical record. |
| WATER SOURCE | The principal source from which cooling water for thermal-electric plants and water for generating power for hydroelectric plants is directly obtained. If more than one water source is (will be) used, enter the name(s) of the other sources of water under "Comments." Enter "municipality" if the water is from a municipality. Enter |

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| | "wells" if water is from wells. Enter "NA" for planned facilities for which water source is not known. |
| WHEELING UTILITY | A utility providing transmission service for another utility or for an independent power producer generator. |
| WINTER PEAK PERIOD | The winter peak period begins on December 1 and runs through the end of February of the following year. For instance, winter 2006 begins December 1, 2006 and runs through the end of February, 2007. It is convenient to describe the winter peak period by means of two years. Thus, the winter referred to here would be winter 2006-2007. |

# APPENDIX D: WESTERN ELECTRICITY COORDINATING COUNCIL CRITERIA FOR UNIFORM REPORTING OF GENERATOR RATINGS

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# APPENDIX A-5-L

## WESTERN ELECTRICITY COORDINATING COUNCIL CRITERIA FOR UNIFORM REPORTING OF GENERATOR RATINGS

A. STEAM TURBO-GENERATOR CAPABILITY
(No regulating or emergency loading limits included)

1. Conditions

   a. All essential equipment available for service.

2. Ratings (report on summer, winter, or monthly basis) –

   Those net kW ratings for individual generating units which the owner is willing to use for regular day-to-day operation. An owner may include units which are not operated on a day-to-day basis but which are maintained in operable condition. Ratings would be based on the capability expected by the operator at the time of the monthly or seasonal peak load. Such ratings will be based on condensing water temperatures and ambient temperatures which influence capability at the time of peak load (use a, b, or c below as it applies to a system's use of the unit).

   a. Unit for a 4-hour period.
   b. Unit for a 10-hour period.
   c. Unit for a 24-hour period.

   For a common header plant, use a, b, or c above on a plant basis.

B. GAS TURBO-GENERATOR CAPABILITY
(No regulating or emergency loading limits included)

1. Conditions

   a. All essential equipment available for service.

2. Ratings (report on summer, winter, or monthly basis) –

   Those net kW ratings for individual generating units which the owner is willing to use for regular day-to-day operation. An owner may include units which are not operated on a day-to-day basis but which are maintained in operable condition. Ratings would be based on the capability expected by the operator at the time of the monthly or seasonal peak load. Such ratings will be based on ambient temperatures which influence capability at the time of peak load (use a, b, c or d below as it applies to a system's use of the unit).

   a. Unit for a 1-hour period.

b. Unit for a 4-hour period.

c. Unit for a 10-hour period.

d. Unit for a 24-hour period.

C. HYDRO TURBO-GENERATOR CAPABILITY
(No regulating or emergency loading limits included)

1. Conditions (Median and Adverse Water)

   a. All essential equipment available for service.

   b. Water conditions based upon minimum head during that period of the month or season when system peak is maximum.

   c. For multiple-unit hydro plants, each unit is assigned a rating by apportioning the combined capabilities among the units.

2. Ratings (report on summer, winter, or monthly basis) –

   Those net kW ratings for the individual generating plant which the owner is willing to use for regular day-to-day operation.

   a. Plant for a 1-hour period.

   b. Plant for a 4-hour period (or longer period if the system's daily peak period is longer than 4 hours).

Prepared and Submitted by the
Operating Studies Work Group

Approved by the Technical Operations
Subcommittee, February 15, 1974

Approved by the Operations Committee
March 14, 1974

Submitted to the Executive Committee
March 21, 1974

Adopted by the Executive Committee
June 20, 1974

# APPENDIX E: LIST OF ELECTRIC UTILITY ORGANIZATIONS WITHIN THE WECC REGION

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# APPENDIX A-5-L

## LIST OF ELECTRIC UTILITY ORGANIZATIONS WITHIN THE WECC REGION

NORTHWEST POWER POOL AREA

| Organizations | | Abbreviation of responsible organization reporting data for this organization |
|---|---|---|
| Alberta Electric System Operator | | AESO |
| ATCO Electric Ltd. | (ATCO) | AESO |
| Calgary AB, City of | | AESO |
| Edmonton Power - AB | (EDP) | AESO |
| Lethbridge AB, City of | | AESO |
| Medicine Hat AB, City of | (CMH) | AESO |
| Red Deer AB, City of | | AESO |
| TransAlta Utilities Corporation - AB | (TAUC) | AESO |
| Avista Corp. | | AVA |
| Bonneville Power Administration | | BPA |
| Federal loads - | | |
| Bureau of Indian Affairs - Wapato, WA | | BPA |
| Bureau of Indian Affairs - Flathead, MT | | BPA |
| Bureau of Mines - OR | | BPA |
| DOE - Richland Operations - WA | | BPA |
| Fairchild Air Force Base - WA | | BPA |
| USBR - Pacific Northwest Region | (USPN) | BPA |
| U. S. Army Corps of Engineers (North Pacific) | (USCE) | BPA |
| U. S. Navy | | BPA |
| Municipal Systems - | | |
| Albion ID, City of | | BPA |
| Ashland OR, City of | | BPA |
| Bandon OR, City of | | BPA |
| Blaine City Light - WA | | BPA |
| Bonners Ferry ID, City of | (BF) | BPA |
| Burley Municipal Distribution System - ID | | BPA |
| Canby OR, City of | | BPA |
| Cascade Locks OR, City of | | BPA |
| Centralia WA, City of | (CC) | BPA |
| Cheney WA, City of | | BPA |
| Chewelah WA, City of | | BPA |
| Consolidated Irrigation District #19 - WA | | BPA |
| Coulee Dam WA, City of | | BPA |
| Declo ID, City of | | BPA |

| | | |
|---|---|---|
| Drain OR, City of | | BPA |
| Eatonville Power & Light Company - WA | | BPA |
| Ellensburg WA, City of | | BPA |
| Eugene Water and Electric Board - OR | (EWEB) | BPA |
| Energy Northwest | | BPA |
| Fircrest WA, Town of | | BPA |
| Forest Grove OR, City of | | BPA |
| Heyburn ID, City of | | BPA |
| McCleary Light & Power - WA | | BPA |
| McMinnville OR, City of | | BPA |
| Milton WA, Town of | | BPA |
| Milton-Freewater Light & Power - OR | | BPA |
| Minidoka ID, City of | | BPA |
| Monmouth OR, City of | | BPA |
| Plummer ID, City of | | BPA |
| Port Angeles WA, City of | | BPA |
| Richland WA, City of | | BPA |
| Rupert ID, City of | | BPA |
| Soda Springs ID, City of | | BPA |
| Springfield Utility Board - OR | | BPA |
| Steilacoom WA, Town of | | BPA |
| Sumas WA, City of | | BPA |
| Troy MT, City of | | BPA |
| Vera Irrigation District No. 15 - WA | | BPA |
| Public Utility Districts - | | |
| Benton County PUD - WA | | BPA |
| Central Lincoln PUD - OR | | BPA |
| Clallam County PUD - WA | | BPA |
| Clatskanie PUD - OR | | BPA |
| Columbia River PUD - OR | | BPA |
| Cowlitz County PUD - WA | (COPD) | BPA |
| Emerald PUD - OR | | BPA |
| Ferry County PUD - WA | | BPA |
| Franklin County PUD - WA | | BPA |
| Grays Harbor County PUD - WA | (GHPD) | BPA |
| Kittitas County PUD - WA | | BPA |
| Klickitat County PUD - WA | | BPA |
| Lewis County PUD - WA | | BPA |
| Mason County PUD No. 1 - WA | | BPA |
| Mason County PUD No. 3 - WA | | BPA |
| Northern Wasco County PUD - OR | | BPA |
| Pacific County PUD No. 2 - WA | | BPA |
| Pend Oreille County PUD - WA | (POPD) | BPA |
| Skamania County PUD - WA | | BPA |
| Snohomish County PUD - WA | (SNPD) | BPA |
| Tillamook PUD - OR | | BPA |

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|---|---|---|
| Wahkiakum County PUD - WA | | BPA |
| Whatcom County PUD - WA | | BPA |
| Cooperatives - | | |
| Alder Mutual Light Company - WA | | BPA |
| Benton Rural Electric Association - WA | (PNGC member) | BPA |
| Big Bend Electric Cooperative, Inc. - WA | | BPA |
| Blachly-Lane Cnty. Coop Elec. Assn. - OR | (PNGC member) | BPA |
| Central Electric Cooperative, Inc. - OR | (PNGC member) | BPA |
| Clearwater Power Company - ID | (PNGC member) | BPA |
| Columbia Basin Electric Cooperative, Inc. - OR | | BPA |
| Columbia Power Cooperative Association - OR | | BPA |
| Columbia Rural Electric Association, Inc. - WA | | BPA |
| Consumers Power, Inc. - OR | (PNGC member) | BPA |
| Coos-Curry Electric Coop, Inc. - OR | (PNGC member) | BPA |
| Douglas Electric Coop, Inc. - OR | (PNGC member) | BPA |
| East End Mutual Electric Company, Ltd. - Rupert, ID | | BPA |
| Elmhurst Mutual Power & Light Company - WA | | BPA |
| Fall River Rural Electric Coop, Inc. - ID | (PNGC member) | BPA |
| Farmers Electric Company - Rupert, ID | | BPA |
| Flathead Electric Cooperative, Inc. - MT | | BPA |
| Glacier Electric Cooperative - MT | | BPA |
| Harney Electric Cooperative, Inc. - OR | | BPA |
| Hood River Electric Cooperative - OR | | BPA |
| Idaho County Light & Power Coop. Assn., Inc. - ID | | BPA |
| Inland Power & Light Company - WA | | BPA |
| Kootenai Electric Cooperative, Inc. - ID | | BPA |
| Lakeview Light & Power Company - WA | | BPA |
| Lane Electric Cooperative, Inc. - OR | (PNGC Member) | BPA |
| Lincoln Electric Cooperative, Inc. - MT | | BPA |
| Lincoln Electric Cooperative, Inc. - WA | (PNGC member) | BPA |
| Lost River Electric Cooperative, Inc. - ID | (PNGC member) | BPA |
| Lower Valley Power & Light, Inc. - WY | (PNGC member) | BPA |
| Midstate Electric Cooperative, Inc. - OR | | BPA |
| Missoula Electric Cooperative, Inc. - MT | | BPA |
| Modern Electric Water Company - WA | | BPA |
| Nespelem Valley Electric Cooperative - WA | | BPA |
| Northern Lights, Inc. - ID | (PNGC Member) | BPA |
| Ohop Mutual Power & Light Company - WA | | BPA |
| Orcas Power & Light Company - WA | | BPA |
| Oregon Trail Cooperative, Inc. - OR | (PNGC Member) | BPA |
| Parkland Light & Water Company - WA | | BPA |
| Peninsula Light Company, Inc. - WA | | BPA |
| Raft River Rural Electric Coop, Inc. - ID | (PNGC member) | BPA |
| Ravalli County Electric Cooperative, Inc. - MT | | BPA |
| Riverside Electric Company - Rupert, ID | | BPA |
| Rural Electric Company - Rupert, ID | | BPA |

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|---|---|---|
| Salem Electric - OR | | BPA |
| Salmon River Electric Cooperative, Inc. - ID | | BPA |
| South Side Electric Lines, Inc. - Declo, ID | | BPA |
| Surprise Valley Electrification Corp. - OR/CA | | BPA |
| Tanner Electric - WA | | BPA |
| Umatilla Electric Cooperative Assn. - OR | (PNGC member) | BPA |
| Unity Light & Power Company - Burley, ID | | BPA |
| Vigilante Electric Cooperative, Inc. - MT | | BPA |
| Wasco Electric Cooperative, Inc. - OR | | BPA |
| Wells Rural Electric Cooperative, Inc. - NV | | BPA |
| West Oregon Electric Cooperative, Inc. - OR | | BPA |
| British Columbia Hydro and Power Authority - Canada | | BCHA |
| West Kootenay Power Ltd. (WKP) | (ILA) | BCHA |
| Chelan County Public Utility District - WA | | CHPD |
| Cashmere WA, City of | | CHPD |
| Colockum Transmission Company | | |
| Douglas County Public Utility District - WA | | DOPD |
| Okanogan PUD - WA | | DOPD |
| Okanogan County Electric Cooperative - WA | | DOPD |
| Grant County Public Utility District - WA | | GCPD |
| Idaho Power Company - ID | | IPC |
| Weiser ID, City of | | IPC |
| NorthWestern Energy - MT | | NWMT |
| Central Montana Electric Power Cooperative | | NWMT |
| Big Horn County Electric Cooperative | | NWMT |
| Mission Valley Power | | NWMT |
| Yellowstone National Park | | NWMT |
| PacifiCorp - East | | PACE |
| Brigham City UT, City of | (UAMP member) | PACE |
| Deaver WY, Town of | | PACE |
| Defense Depot Ogden - UT | | PACE |
| Deseret Generation & Transmission Co-operative | (DGT) | PACE |
| Bridger Valley Electric Association, Inc. - WY | (DGT) | PACE |
| Dixie-Escalante REA - UT | (DGT) | PACE |
| Flowell Electric Association - UT | (DGT) | PACE |
| Garkane Electric Association - UT/AZ | (DGT) | PACE |
| Kanab UT, City of | (DGT) | PACE |
| Moon Lake Electric Association - UT | (DGT) | PACE |
| Mt. Wheeler Power Association - NV | (DGT) | PACE |
| Helper UT, City of | | PACE |

# APPENDIX A-5-L

| | | |
|---|---|---|
| Helper UT, Annex | | PACE |
| Hill Air Force Base - UT | | PACE |
| Montana Dakota Utilities Company - WY | | PACE |
| Price UT, City of | (UAMP member) | PACE |
| Tooele Army Depot - UT | | PACE |
| University of Utah - UT | | PACE |
| Utah Associated Municipal Power Systems - UT | (UAMP) | PACE |
| Beaver UT, City of | (UAMP) | PACE |
| Blanding UT, City of | (UAMP) | PACE |
| Bountiful UT, City of | (UAMP) | PACE |
| Central Utah Water Conservancy District | (UAMP) | PACE |
| Colorado City AZ, City of | (UAMP) | PACE |
| Enterprise UT, City of | (UAMP) | PACE |
| Ephraim UT, City of | (UAMP) | PACE |
| Fairview UT, City of | (UAMP) | PACE |
| Fillmore UT, City of | (UAMP) | PACE |
| Fredonia AZ, Town of | (UAMP) | PACE |
| Heber Light & Power - UT | (UAMP) | PACE |
| Hilldale UT, City of | (UAMP) | PACE |
| Holden UT, Town of | (UAMP) | PACE |
| Hurricane UT, City of | (UAMP) | PACE |
| Hyrum UT, City of | (UAMP) | PACE |
| Idaho Falls ID, City of | (UAMP) | PACE |
| Kanosh UT, City of | (UAMP) | PACE |
| Kaysville UT, City of | (UAMP) | PACE |
| Lehi UT, City of | (UAMP) | PACE |
| Logan UT, City of | (UAMP) | PACE |
| Meadow UT, City of | (UAMP) | PACE |
| Monroe UT, City of | (UAMP) | PACE |
| Morgan UT, City of | (UAMP) | PACE |
| Mount Pleasant UT, City of | (UAMP) | PACE |
| Murray City Corporation - UT | (UAMP) | PACE |
| Oak City - UT | (UAMP) | PACE |
| Page AZ, City of | (UAMP) | PACE |
| Paragona UT, Town of | (UAMP) | PACE |
| Parowan UT, City of | (UAMP) | PACE |
| Payson UT, City of | (UAMP) | PACE |
| Saint George UT, City of | (UAMP) | PACE |
| Santa Clara UT, City of | (UAMP) | PACE |
| Spring City - UT | (UAMP) | PACE |
| Springville UT, City of | (UAMP) | PACE |
| Strawberry Water Users Assoc. - UT | (UAMP) | PACE |
| Utah State University | (UAMP) | PACE |
| Washington UT, City of | (UAMP) | PACE |
| Weber Basin Water Conservancy District - UT | (UAMP) | PACE |
| Utah Municipal Power Agency | (UMPA) | PACE |
| Levan UT, Town of | (UMPA) | PACE |

# APPENDIX A-5-L

| | | |
|---|---|---|
| Manti UT, City of | (UMPA) | PACE |
| Nephi UT, City of | (UMPA) | PACE |
| Provo UT, City of | (UMPA) | PACE |
| Salem UT, City of | (UMPA) | PACE |
| Spanish Fork UT, City of | (UMPA) | PACE |
| Western Area Power Administration - Salt Lake | (WAUC) | PACE |
| CUP - Bonneville Unit | (WAUC) | PACE |
| CUP - Jensen Unit | (WAUC) | PACE |
| USBR - Upper Colorado Region | (WAUC) | PACE |
| Uintah Water Conservancy Dist. | (WAUC) | PACE |
| PacifiCorp - West | | PACW |
| Clark County PUD - WA | (CLPD) | PACW |
| Portland General Electric Company - OR | | PGE |
| Puget Sound Energy - WA | | PSE |
| Seattle Department of Light (Seattle City Light) - WA | | SCL |
| Sierra Pacific Power Company - NV | | SPP |
| Tacoma Power - WA | | TPWR |
| Ruston Electric Utility - WA | | TPWR |
| Western Area Power Administration – Great Plains - West | | WAUW |

# APPENDIX A-5-L

ROCKY MOUNTAIN POWER AREA

| Organizations | | Abbreviation of responsible organization reporting data for this organization |
|---|---|---|
| Public Service Company of Colorado | | PSC |
| Aquila Networks-WPC | (WPE) | PSC |
| Arkansas River Power Authority | (ARPA) | PSC |
| Granada CO, City of - (non-ARPA member) | (ARPA) | PSC |
| Holly CO, City of | (ARPA) | PSC |
| La Junta CO, City of | (ARPA) | PSC |
| Las Animas CO, City of | (ARPA) | PSC |
| Lamar CO, City of | (ARPA) | PSC |
| Raton NM, City of | (ARPA) | PSC |
| Springfield CO, City of | (ARPA) | PSC |
| Trinidad CO, City of | (ARPA) | PSC |
| Burlington CO, City of | | PSC |
| Center CO, City of | | PSC |
| DOE - Rocky Flats | | PSC |
| Glenwood Springs CO, City of | | PSC |
| Grand Valley Rural Power Lines - Grand Junction CO | | PSC |
| Holy Cross Electric Association - Glenwood Springs CO | | PSC |
| Intermountain Rural Electric Assn. - Sedalia CO | | PSC |
| Julesburg CO, City of | | PSC |
| Tri-State Generation and Transmission Association, Inc. | TSGT | WACM |
| Big Horn Rural Electric Co. - Basin WY | TSGT | WACM |
| Carbon Power & Light - Saratoga WY | TSGT | WACM |
| Chimney Rock Public Power District - West - Bayard NE | TSGT | WACM |
| Delta-Montrose Rural Power Lines - Delta CO | TSGT | WACM |
| Empire Electric Association - Cortez CO | TSGT | WACM |
| Garland Light & Power - Powell WY | TSGT | WACM |
| Gunnison County Electric Assn. - Crested Butte CO | TSGT | WACM |
| Highline Electric Association - West - Holyoke CO | TSGT | WACM |
| Hot Springs County REA - Thermopolis WY | TSGT | WACM |
| K. C. Electric Association - Hugo CO | TSGT | WACM |
| La Plata Electric Association - Durango CO | TSGT | WACM |
| Morgan County Rural Electric Assn. - Fort Morgan CO | TSGT | WACM |
| Mountain Parks Electric - Granby CO | TSGT | WACM |
| Mountain View Electric Association - Limon CO | TSGT | WACM |
| Niobrara Electric Association, Inc. - Lusk WY | TSGT | WACM |
| Poudre Valley Rural Electric Assn. - Fort Collins CO | TSGT | WACM |
| Riverton Valley Electric Association - Riverton WY | TSGT | WACM |
| Roosevelt Public Power District - Mitchell NE | TSGT | WACM |
| Rural Electric Company - Pine Bluffs CO | TSGT | WACM |
| San Isabel Electric Service, Inc. - Pueblo CO | TSGT | WACM |
| San Luis Valley Rural Electric Coop - Monte Vista CO | TSGT | WACM |

| | | | |
|---|---|---|---|
| San Miguel Power Association - Nucla CO | | TSGT | WACM |
| Sangre De Cristo Electric Assn. - Buena Vista CO | | TSGT | WACM |
| Sheridan-Johnson Rural Electric Assn. - Sheridan WY | | TSGT | WACM |
| Southeast Colorado Power Association - La Junta CO | | TSGT | WACM |
| United Power, Inc. - Brighton CO | | TSGT | WACM |
| Wheatbelt Public Power District - West - Sidney NE | | TSGT | WACM |
| Wheatland Rural Electric Association - Wheatland WY | | TSGT | WACM |
| White River Electric Association - Meeker CO | | TSGT | WACM |
| Wyrulec Company - Lingle WY | | TSGT | WACM |
| Y-W Electric Association - Akron CO | | TSGT | WACM |
| Delta CO, City of | (non-TSGT member) | TSGT | WACM |
| Frederick CO, City of | (non-TSGT member) | TSGT | WACM |
| Northern Colorado Water Cons. Dist. | (non-TSGT member) | TSGT | WACM |
| Torrington WY, City of | (non-TSGT member) | TSGT | WACM |
| Wray CO, City of | (non-TSGT member) | TSGT | WACM |
| Yampa Valley Electric Assn. - Steamboat Springs CO | | | PSC |
| | | | |
| Western Area Power Administration - Colorado-Missouri Region | | | WACM |
| Basin Electric Power Cooperative - west | | (BEPC) | WACM |
| Rushmore Electric Power Cooperative | | (BEPC) | WACM |
| Tri-County Electric Association, Inc. | | (BEPC) | WACM |
| Basin WY, Town of | | (RMGC member) | WACM |
| Black Hills Power and Light Company | | (BHPL) | WACM |
| Gillette WY, City of | | (BHPL) | WACM |
| Upton, City of | | (BHPL) | WACM |
| South Dakota State Cement Plant | | (BHPL) | WACM |
| South Dakota School of Mines & Technology | | (BHPL) | WACM |
| Cody WY, City of | | (WMPA member) | WACM |
| Colorado River Pumps (7) | | | WACM |
| Colorado Springs Utilities | | (CSU) | WACM |
| Air Force Academy | | (CSU) | WACM |
| Fountain CO, City of | | (CSU) | WACM |
| Norad | | (CSU) | WACM |
| Peterson Air Force Base | | (CSU) | WACM |
| Denver Water Board | | | WACM |
| Forest Service | | | WACM |
| Fort Laramie WY, City of | | (WMPA member) | WACM |
| Goshen Irrigation District | | | WACM |
| Guernsey WY, City of | | (WMPA member) | WACM |
| Highland-Hanover Irrigation District | | | WACM |
| Lingle WY, City of | | (WMPA member) | WACM |
| Lusk WY, City of | | (WMPA member) | WACM |
| Midvale Irrigation District | | | WACM |
| Municipal Energy Agency of Nebraska | | (MEAN) | WACM |
| Aspen CO, City of | | (MEAN) | WACM |
| Bayard NE, City of | | (MEAN) | WACM |
| Bridgeport NE, City of | | (MEAN) | WACM |

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| | | |
|---|---|---|
| Fleming CO, City of | (MEAN) | WACM |
| Fort Morgan CO, City of - (RMGC member) | (MEAN) | WACM |
| Gering NE, City of | (MEAN) | WACM |
| Gunnison CO, City of | (MEAN) | WACM |
| Haxtun CO, City of | (MEAN) | WACM |
| Holyoke CO, City of - (RMGC member) | (MEAN) | WACM |
| Kimball NE, City of | (MEAN) | WACM |
| Lyman NE, City of | (MEAN) | WACM |
| Lyons CO, City of | (MEAN) | WACM |
| Mitchell NE, City of | (MEAN) | WACM |
| Morrill NE, City of | (MEAN) | WACM |
| Oak Creek CO, City of | (MEAN) | WACM |
| Sidney NE, City of | (MEAN) | WACM |
| Yuma CO, City of | (MEAN) | WACM |
| National Park Service | | WACM |
| Owl Creek Irrigation District | | WACM |
| Pine Bluffs WY, City of | (WMPA member) | WACM |
| Powell WY, City of | (WMPA member) | WACM |
| Pueblo Army Depot, CO | | WACM |
| Tri-State Generation and Transmission Association, Inc. | TSGT | WACM |
| Big Horn Rural Electric Co. - Basin WY | TSGT | WACM |
| Carbon Power & Light - Saratoga WY | TSGT | WACM |
| Chimney Rock Public Power District - West - Bayard NE | TSGT | WACM |
| Delta-Montrose Rural Power Lines - Delta CO | TSGT | WACM |
| Empire Electric Association - Cortez CO | TSGT | WACM |
| Garland Light & Power - Powell WY | TSGT | WACM |
| Gunnison County Electric Assn. - Crested Butte CO | TSGT | WACM |
| Highline Electric Association - West - Holyoke CO | TSGT | WACM |
| Hot Springs County REA - Thermopolis WY | TSGT | WACM |
| K. C. Electric Association - Hugo CO | TSGT | WACM |
| La Plata Electric Association - Durango CO | TSGT | WACM |
| Morgan County Rural Electric Assn. - Fort Morgan CO | TSGT | WACM |
| Mountain Parks Electric - Granby CO | TSGT | WACM |
| Mountain View Electric Association - Limon CO | TSGT | WACM |
| Niobrara Electric Association, Inc. - Lusk WY | TSGT | WACM |
| Poudre Valley Rural Electric Assn. - Fort Collins CO | TSGT | WACM |
| Riverton Valley Electric Association - Riverton WY | TSGT | WACM |
| Roosevelt Public Power District - Mitchell NE | TSGT | WACM |
| Rural Electric Company - Pine Bluffs CO | TSGT | WACM |
| San Isabel Electric Service, Inc. - Pueblo CO | TSGT | WACM |
| San Luis Valley Rural Electric Coop - Monte Vista CO | TSGT | WACM |
| San Miguel Power Association - Nucla CO | TSGT | WACM |
| Sangre De Cristo Electric Assn. - Buena Vista CO | TSGT | WACM |
| Sheridan-Johnson Rural Electric Assn. - Sheridan WY | TSGT | WACM |
| Southeast Colorado Power Association - La Junta CO | TSGT | WACM |
| United Power, Inc. - Brighton CO | TSGT | WACM |
| Wheatbelt Public Power District - West - Sidney NE | TSGT | WACM |

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| | | | |
|---|---|---|---|
| Wheatland Rural Electric Association - Wheatland WY | | TSGT | WACM |
| White River Electric Association - Meeker CO | | TSGT | WACM |
| Wyrulec Company - Lingle WY | | TSGT | WACM |
| Y-W Electric Association - Akron CO | | TSGT | WACM |
| Delta CO, City of | (non-TSGT member) | TSGT | WACM |
| Frederick CO, City of | (non-TSGT member) | TSGT | WACM |
| Northern Colorado Water Cons. Dist. | (non-TSGT member) | TSGT | WACM |
| Torrington WY, City of | (non-TSGT member) | TSGT | WACM |
| Wray CO, City of | (non-TSGT member) | TSGT | WACM |
| Upper Bluff Irrigation District | | | WACM |
| USBR - Animas - La Plata | | | WACM |
| USBR - Dolores Project | | | WACM |
| USBR - Paradox | | | WACM |
| Warren Air Force Base - WY | | (RMGC member) | WACM |
| Wheatland WY, City of | | (WMPA member) | WACM |
| Willwood Light & Power - WY | | (RMGC member) | WACM |
| Silt Water Conservancy District | | (WAUC) | WACM |
| Uintah Water Conservancy District | | (WAUC) | WACM |

# APPENDIX A-5-L

ARIZONA-NEW MEXICO-SOUTHERN NEVADA POWER AREA

| Organizations | | Abbreviation of responsible organization reporting data for this organization |
|---|---|---|
| Arizona Public Service Company | | APS |
| Aguila Irrigation District | | APS |
| Ajo Improvement Company | | APS |
| Ak-Chin Indian Community | | APS |
| Buckeye Water Conservancy District | (APA member) | APS |
| Citizens Utilities Company | (CUC) | APS |
| Colorado River Agency | | APS |
| Electrical District No. 1 - Pinal, AZ | | APS |
| Electrical District No. 3 - Pinal, AZ | (APA member) | APS |
| Electrical District No. 6 - Pinal, AZ | (APA member) | APS |
| Electrical District No. 7 - Maricopa, AZ | (APA member) | APS |
| Electrical District No. 8 - Maricopa, AZ | | APS |
| Gila Bend Air Force Base | | APS |
| Harquahala P.D. | | APS |
| Luke Air Force Base | | APS |
| Maricopa MWCD No. 1 | (APA member) | APS |
| Marine Corps Air Station | | APS |
| McMullen Valley W.C.&D. | | APS |
| Mojave County | | APS |
| Roosevelt Irrigation District | (APA member) | APS |
| Tohono O'odham Utility Authority | (TOUA) | APS |
| Tonopah Irrigation District | | APS |
| Wickenburg Electrical Department | | APS |
| Yuma Irrigation District - residential | | APS |
| Yuma Proving Grounds - DOD | | APS |
| Duke – Arlington Valley | | DEAA |
| El Paso Electric Company | | EPE |
| Rio Grande Electric Cooperative, Inc. | | EPE |
| Gila River Maricopa Arizona | | GRMA |
| Harquahala Generator Maricopa Arizona | | HGMA |
| Imperial Irrigation District | | IID |
| Nevada Power Company | | NEVP |
| City of Boulder City - NV | (CBC) | NEVP |
| DOE/NTS | | NEVP |
| Fort Mojave Indian Tribe - AZ | | NEVP |

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| | | | |
|---|---|---|---|
| Lincoln County Power District #1 | | | NEVP |
| Littlefield Electric Coop. - AZ | | | NEVP |
| Needles CA, City of | | | NEVP |
| Nellis Air Force Base | | | NEVP |
| Overton Power District #5 | | | NEVP |
| State of Nevada (Colorado River Commission) (CRCN) | | | NEVP |
| Valley Electric Association | | | NEVP |
| | | | |
| Public Service Company of New Mexico | | | PNM |
| Eastern New Mexico Coops | | | PNM |
| Gallup NM, City of | | | PNM |
| Holloman AFB | | | PNM |
| Kirtland AFB | | | PNM |
| Los Alamos County - NM | | (LAC) | PNM |
| DOE - Albuquerque | | (LAC) | PNM |
| Navajo Agricultural Products Industry | | (NAPI) | PNM |
| Texas-New Mexico Power Company | | (TNP) | PNM |
| Tri-State Generation and Transmission Association, Inc. | | TSGT | PNM |
| Central New Mexico Electric Cooperative, Inc. | | TSGT | PNM |
| Columbus Electric Cooperative, Inc. | | TSGT | PNM |
| Continental Divide Electric Cooperative, Inc. | | TSGT | PNM |
| Jemez Mountains Electric Cooperative, Inc. | | TSGT | PNM |
| Kit Carson Electric Cooperative, Inc. | | TSGT | PNM |
| Mora-San Miguel Electric Cooperative, Inc. | | TSGT | PNM |
| Navopache Electric Cooperative, Inc. | | TSGT | PNM |
| Northern Rio Arriba Electric Cooperative, Inc. | | TSGT | PNM |
| Otero Electric Cooperative, Inc. | | TSGT | PNM |
| Sierra Electric Cooperative, Inc. | | TSGT | PNM |
| Socorro Electric Cooperative, Inc. | | TSGT | PNM |
| Southwestern Electric Cooperative, Inc. | | TSGT | PNM |
| Springer Electric Cooperative Inc. | | TSGT | PNM |
| Truth or Consequences NM, City of | (non-TSGT member) | TSGT | PNM |
| | | | |
| Salt River Project | | | SRP |
| Arizona Power Authority | | (APA) | SRP |
| Chandler Heights Citrus IP | | (APA member) | SRP |
| Electrical District No. 5 - Maricopa, AZ | | (APA member) | SRP |
| Electrical District No. 6 - Pinal, AZ | | (APA member) | SRP |
| Ocotillo Water Conservation District | | (APA member) | SRP |
| Queen Creek Irrigation District | | (APA member) | SRP |
| Roosevelt Irrigation District | | (APA member) | SRP |
| Roosevelt Water Conservation District | | (APA member) | SRP |
| Central Arizona Water Conservation District | | | SRP |
| Electrical District No. 4 - Pinal, AZ | | | SRP |
| Electrical District No. 5 - Pinal, AZ | | | SRP |
| San Tan Irrigation District | | | SRP |

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| | | | |
|---|---|---|---|
| Tucson Electric Power Company | | | TEP |
| Cortaro Marana Irrigation District | | (APA member) | TEP |
| Navajo Tribal Utility Authority | | (NTUA) | TEP |
| Western Area Power Administration - Lower Colorado Region | | | WALC |
| Arizona Electric Power Cooperative | (AZPPA member) | (AEPC) | WALC |
| Anza Electric Cooperative | | (AEPC) | WALC |
| Arizona Power Pooling Association | (AZPPA) | (AEPC) | WALC |
| Avra Valley | | (AEPC) | WALC |
| Duncan Valley Cooperative | | (AEPC) | WALC |
| Electrical District No. 2 - Pinal, AZ | (AZPPA member) | (AEPC) | WALC |
| Graham County Electric Cooperative | | (AEPC) | WALC |
| Mesa AZ, City of | (AZPPA member) | (AEPC) | WALC |
| Mohave Electric Cooperative | | (AEPC) | WALC |
| Safford AZ, City of | | (AEPC) | WALC |
| San Carlos Irrigation Project (SCIP) | (AZPPA member) | (AEPC) | WALC |
| Silverbell | | (AEPC) | WALC |
| Sulphur Springs Valley Cooperative | | (AEPC) | WALC |
| Thatcher AZ, City of | | (AEPC) | WALC |
| Tohono O'odham Utility Authority | (TOUA) | (AEPC) | WALC |
| Trico Electric Cooperative | | (AEPC) | WALC |
| Farmington NM, City of | | (FARM) | WALC |
| Aztec NM, City of | | (FARM) | WALC |
| Wellton-Mohawk Irrigation District | | | WALC |
| USBR - Protective Regulatory Pumps | | | WALC |
| USBR - Yuma Desalting Plant | | | WALC |
| USBR - Yuma Project | | | WALC |
| Yuma Irrigation District | | | WALC |

# APPENDIX A-5-L

CALIFORNIA-MEXICO POWER AREA

| Organizations | | Abbreviation of responsible organization reporting data for this organization |
|---|---|---|
| California Independent System Operator | | CISO |
| Department of Water Resources/California | (CDWR) | CISO |
| Metropolitan Water District/Southern California | (MWD) | CISO |
| Northern California Power Agency | (NCPA) | CISO |
| Alameda CA, City of | (NCPA) | CISO |
| Biggs CA, City of | (NCPA) | CISO |
| Gridley CA, City of | (NCPA) | CISO |
| Healdsburg CA, City of | (NCPA) | CISO |
| Lodi CA, City of | (NCPA) | CISO |
| Lompoc CA, City of | (NCPA) | CISO |
| Oakland, Port of | (NCPA) | CISO |
| Palo Alto CA, City of | (NCPA) | CISO |
| Plumas-Sierra Rural Electric Cooperative | (NCPA) | CISO |
| Ukiah CA, City of | (NCPA) | CISO |
| Pacific Gas & Electric Company | (PG&E) | CISO |
| Calaveras Public Power Agency | (PG&E) | CISO |
| East Bay Municipal Utility District | (PG&E) | CISO |
| Lassen County Municipal Utility District | (PG&E) | CISO |
| Merced Irrigation District | (PG&E) | CISO |
| Nevada Irrigation District | (PG&E) | CISO |
| Oakdale Irrigation District | (PG&E) | CISO |
| Oroville-Wyandotte Irrigation District | (PG&E) | CISO |
| Placer County Water Agency | (PG&E) | CISO |
| San Francisco, City and County of - loads only | (PG&E) | CISO |
| Shelter Cove Improvement District | (PG&E) | CISO |
| Solano Irrigation District | (PG&E) | CISO |
| South San Joaquin Irrigation District | (PG&E) | CISO |
| Trinity County Public Utility District | (PG&E) | CISO |
| Tuolumne County Public Power Agency | (PG&E) | CISO |
| Yuba County Water Agency | (PG&E) | CISO |
| Pasadena CA, City of | (PASA) | CISO |
| San Diego Gas & Electric Company | (SDGE) | CISO |
| Santa Clara CA, City of - NCPA, CCPA & MSR member | (SNCL) | CISO |
| Southern California Edison Company | (SCE) | CISO |
| Edwards Air Force Base | (SCE) | CISO |
| March Air Force Base | (SCE) | CISO |
| SCE Blythe District | (SCE) | CISO |
| Anaheim CA, City of | (ANHM) | CISO |
| Azusa CA, City of | (AZSA) | CISO |
| Banning CA, City of | (BNNG) | CISO |
| Colton CA, City of | (CLTN) | CISO |

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| | | |
|---|---|---|
| Riverside CA, City of | (RVSD) | CISO |
| Vernon CA, City of | (VERN) | CISO |
| San Francisco, City and County of - resources only | (CCSF) | CISO |
| Transmission Agency of Northern California | (TANC) | CISO |
| WASN loads wheeled by PG&E | | |
| Ames Research Center (NASA) | | CISO |
| Arvin-Edison Water District (IP) | | CISO |
| Avenal, City of | | CISO |
| Banta-Carbona Irrigation District (IP) | | CISO |
| Bay Area Rapid Transit | | CISO |
| Beale Air Force Base | | CISO |
| Broadview Water District | | CISO |
| Byron-Bethany Irrigation District (IP) | | CISO |
| Camp Parks (Provisional) | | CISO |
| Cawela Water District | | CISO |
| Coleman National Fish Hatchery | | CISO |
| Defense District Depot (Sharpe Facility) (DLA) | | CISO |
| Defense District Depot (Tracy Facility) (DLA) | | CISO |
| Delano/Lindsay/Terra (IP) | | CISO |
| Deuel Vocation Institution | | CISO |
| DOE - Lawrence Berkeley Lab | | CISO |
| DOE - Site 300 | | CISO |
| DOE - Stanford Linear Accelerator Center | | CISO |
| Glenn-Colusa Irrigation District (IP) | | CISO |
| Inter. Comm. Ag. - Dixon | | CISO |
| James Irrigation District | | CISO |
| Kern-Tulare River Water District | | CISO |
| Lassen Municipal Utility District | | CISO |
| Lower Tule Water District | | CISO |
| Mare Island Naval Shipyard | | CISO |
| Naval Air Station - Lemoore | | CISO |
| Naval Air Station - Moffett Field | | CISO |
| Naval Comm. Station - Stockton | | CISO |
| Naval Radio Station - Dixon | | CISO |
| Naval Weapons Station - Concord | | CISO |
| Northern California Youth Center | | CISO |
| Oakland Naval Supply Center | | CISO |
| Onizuka Air Force Base | | CISO |
| Parks Reserve Forces Training Area - Dublin (DLA) | | CISO |
| Patterson Water District (IP) | | CISO |
| Provident Irrigation District (IP) | | CISO |
| Reclamation Dist. 2035 (Main) (IP) | | CISO |
| Reclamation Dist. 2035 (Booster) (IP) | | CISO |
| Santa Clara Valley Water District | | CISO |
| San Luis Water District | | CISO |
| Sierra Conservation | | CISO |
| Sonoma County WA | | CISO |

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| | | |
|---|---|---|
| Travis Air Force Base | | CISO |
| Travis Wherry Housing | | CISO |
| University of California - Davis | | CISO |
| Vacaville Medical Facility | | CISO |
| Westlands Water District (IP) | | CISO |
| W. Stanislaus Irrigation District (IP) | | CISO |
| West Side Irrigation District | | CISO |
| Comision Federal de Electricidad - northern Baja only | | CFE |
| Los Angeles Department of Water & Power | | LDWP |
| Burbank CA, City of | (BURB) | LDWP |
| Glendale CA, City of | (GLEN) | LDWP |
| Sacramento Municipal Utility District - CCPA member | | SMUD |
| Folsom State Prison | | SMUD |
| McClellan Air Force Base | | SMUD |
| Modesto Irrigation District - CCPA & MSR member | (MID) | SMUD |
| Redding CA, City of - NCPA, CCPA & MSR member | (RDNG/WASN) | SMUD |
| Roseville CA, City of | (NCPA/WASN) | SMUD |
| Western Area Power Administration - Sierra Nevada Region | (WASN) | SMUD |
| California State Parks - Folsom | (WASN) | SMUD |
| CSUS - Nimbus | (WASN) | SMUD |
| DOE - Lawrence Livermore National Lab | (WASN) | SMUD |
| Shasta Lake, City of | (WASN) | SMUD |
| Turlock Irrigation District - NCPA member | | TIDC |

# APPENDIX F: STATE AND COUNTY CODES

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# APPENDIX A-5-L

## STATE AND COUNTY CODES

State Name: **ARIZONA**

State Code: 04

| County Name | County Code |
|---|---|
| Apache | 001 |
| Cochise | 003 |
| Coconino | 005 |
| Gila | 007 |
| Graham | 009 |
| Greenlee | 011 |
| Maricopa | 013 |
| Mohave | 015 |
| Navajo | 017 |
| Pima | 019 |
| Pinal | 021 |
| Santa Cruz | 023 |
| Yavapai | 025 |
| Yuma | 027 |

State Name: **CALIFORNIA**

State Code: 06

| County Name | County Code |
|---|---|
| Alameda | 001 |
| Alpine | 003 |
| Amador | 005 |
| Butte | 007 |
| Calaveras | 009 |
| Colusa | 011 |
| Contra Costa | 013 |
| Del Norte | 015 |
| El Dorado | 017 |
| Fresno | 019 |
| Glenn | 021 |
| Humboldt | 023 |
| Imperial | 025 |
| Inyo | 027 |
| Kern | 029 |
| Kings | 031 |
| Lake | 033 |
| Lassen | 035 |
| Los Angeles | 037 |
| Madera | 039 |
| Marin | 041 |
| Mariposa | 043 |
| Mendocino | 045 |
| Merced | 047 |
| Modoc | 049 |
| Mono | 051 |
| Monterey | 053 |
| Napa | 055 |
| Nevada | 057 |
| Orange | 059 |
| Placer | 061 |
| Plumas | 063 |
| Riverside | 065 |
| Sacramento | 067 |
| San Benito | 069 |
| San Bernardino | 071 |
| San Diego | 073 |
| San Francisco | 075 |
| San Joaquin | 077 |
| San Luis Obispo | 079 |
| San Mateo | 081 |
| Santa Barbara | 083 |
| Santa Clara | 085 |
| Santa Cruz | 087 |
| Shasta | 089 |
| Sierra | 091 |
| Siskiyou | 093 |
| Solano | 095 |
| Sonoma | 097 |
| Stanislaus | 099 |
| Sutter | 101 |
| Tehama | 103 |
| Trinity | 105 |
| Tulare | 107 |
| Tuolumne | 109 |
| Ventura | 111 |
| Yolo | 113 |
| Yuba | 115 |

State Name: **COLORADO**

State Code: 08

| County Name | County Code |
|---|---|
| Adams | 001 |
| Alamosa | 003 |
| Arapahoe | 005 |
| Archuleta | 007 |
| Baca | 009 |
| Bent | 011 |
| Boulder | 013 |
| Chaffee | 015 |
| Cheyenne | 017 |
| Clear Creek | 019 |
| Conejos | 021 |
| Costilla | 023 |
| Crowley | 025 |
| Custer | 027 |
| Delta | 029 |
| Denver | 031 |
| Dolores | 033 |
| Douglas | 035 |
| Eagle | 037 |
| Elbert | 039 |
| El Paso | 041 |
| Fremont | 043 |
| Garfield | 045 |
| Gilpin | 047 |
| Grand | 049 |
| Gunnison | 051 |
| Hinsdale | 053 |
| Huerfano | 055 |
| Jackson | 057 |
| Jefferson | 059 |
| Kiowa | 061 |
| Kit Carson | 063 |
| Lake | 065 |
| La Plata | 067 |
| Larimer | 069 |
| Las Animas | 071 |
| Lincoln | 073 |
| Logan | 075 |
| Mesa | 077 |
| Mineral | 079 |
| Moffat | 081 |
| Montezuma | 083 |
| Montrose | 085 |
| Morgan | 087 |
| Otero | 089 |
| Ouray | 091 |
| Park | 093 |
| Phillips | 095 |
| Pitkin | 097 |

| | |
|---|---|
| Prowers | 099 |
| Pueblo | 101 |
| Rio Blanco | 103 |
| Rio Grande | 105 |
| Routt | 107 |
| Saguache | 109 |
| San Juan | 111 |
| San Miguel | 113 |
| Sedgwick | 115 |
| Summit | 117 |
| Teller | 119 |
| Washington | 121 |
| Weld | 123 |
| Yuma | 125 |

State Name: **IDAHO**

State Code: 16

| County Name | County Code |
|---|---|
| Ada | 001 |
| Adams | 003 |
| Bannock | 005 |
| Bear Lake | 007 |
| Benewah | 009 |
| Bingham | 011 |
| Blaine | 013 |
| Boise | 015 |
| Bonner | 017 |
| Bonneville | 019 |
| Boundary | 021 |
| Butte | 023 |
| Camas | 025 |
| Canyon | 027 |
| Caribou | 029 |
| Cassia | 031 |
| Clark | 033 |
| Clearwater | 035 |
| Custer | 037 |
| Elmore | 039 |
| Franklin | 041 |
| Fremont | 043 |
| Gem | 045 |
| Gooding | 047 |
| Idaho | 049 |
| Jefferson | 051 |
| Jerome | 053 |
| Kootenai | 055 |
| Latah | 057 |
| Lemhi | 059 |
| Lewis | 061 |
| Lincoln | 063 |
| Madison | 065 |
| Minidoka | 067 |
| Nez Perce | 069 |
| Oneida | 071 |
| Owyhee | 073 |
| Payette | 075 |
| Power | 077 |
| Shoshone | 079 |
| Teton | 081 |
| Twin Falls | 083 |
| Valley | 085 |
| Washington | 087 |

State Name: **MONTANA**

State Code: 30

| County Name | County Code |
|---|---|
| Beaverhead | 001 |
| Big Horn | 003 |
| Blaine | 005 |
| Broadwater | 007 |
| Carbon | 009 |
| Carter | 011 |
| Cascade | 013 |
| Chouteau | 015 |
| Custer | 017 |
| Daniels | 019 |
| Dawson | 021 |
| Deer Lodge | 023 |
| Fallon | 025 |
| Fergus | 027 |
| Flathead | 029 |
| Gallatin | 031 |
| Garfield | 033 |
| Glacier | 035 |
| Golden Valley | 037 |
| Granite | 039 |
| Hill | 041 |
| Jefferson | 043 |
| Judith Basin | 045 |
| Lake | 047 |
| Lewis and Clark | 049 |
| Liberty | 051 |
| Lincoln | 053 |
| McCone | 055 |
| Madison | 057 |
| Meagher | 059 |
| Mineral | 061 |
| Missoula | 063 |
| Musselshell | 065 |
| Park | 067 |
| Petroleum | 069 |
| Phillips | 071 |
| Pondera | 073 |
| Powder River | 075 |
| Powell | 077 |
| Prairie | 079 |
| Ravalli | 081 |
| Richland | 083 |
| Roosevelt | 085 |
| Rosebud | 087 |
| Sanders | 089 |
| Sheridan | 091 |
| Silver Bow | 093 |
| Stillwater | 095 |
| Sweet Grass | 097 |
| Teton | 099 |
| Toole | 101 |
| Treasure | 103 |
| Valley | 105 |
| Wheatland | 107 |
| Wibaux | 109 |
| Yellowstone | 111 |
| Yellowstone Nat'l. Park-Part | 113 |

State Name: **NEBRASKA**

State Code: 31

| County Name | County Code |
|---|---|
| Adams | 001 |
| Antelope | 003 |
| Arthur | 005 |
| Banner | 007 |
| Blaine | 009 |
| Boone | 011 |
| Box Butte | 013 |
| Boyd | 015 |
| Brown | 017 |

# APPENDIX A-5-L

| | |
|---|---|
| Buffalo | 019 |
| Burt | 021 |
| Butler | 023 |
| Cass | 025 |
| Cedar | 027 |
| Chase | 029 |
| Cherry | 031 |
| Cheyenne | 033 |
| Clay | 035 |
| Colfax | 037 |
| Cuming | 039 |
| Custer | 041 |
| Dakota | 043 |
| Dawes | 045 |
| Dawson | 047 |
| Deuel | 049 |
| Dixon | 051 |
| Dodge | 053 |
| Douglas | 055 |
| Dundy | 057 |
| Fillmore | 059 |
| Franklin | 061 |
| Frontier | 063 |
| Furnas | 065 |
| Gage | 067 |
| Garden | 069 |
| Garfield | 071 |
| Gosper | 073 |
| Grant | 075 |
| Greeley | 077 |
| Hall | 079 |
| Hamilton | 081 |
| Harlan | 083 |
| Hayes | 085 |
| Hitchcock | 087 |
| Holt | 089 |
| Hooker | 091 |
| Howard | 093 |
| Jefferson | 095 |
| Johnson | 097 |
| Kearney | 099 |
| Keith | 101 |
| Keya Paha | 103 |
| Kimball | 105 |
| Knox | 107 |
| Lancaster | 109 |
| Lincoln | 111 |
| Logan | 113 |
| Loup | 115 |
| McPherson | 117 |
| Madison | 119 |
| Merrick | 121 |
| Morrill | 123 |
| Nance | 125 |
| Nemaha | 127 |
| Nuckolls | 129 |
| Otoe | 131 |
| Pawnee | 133 |
| Perkins | 135 |
| Phelps | 137 |
| Pierce | 139 |
| Platte | 141 |
| Polk | 143 |
| Red Willow | 145 |
| Richardson | 147 |
| Rock | 149 |
| Saline | 151 |
| Sarpy | 153 |
| Saunders | 155 |
| Scotts Bluff | 157 |
| Seward | 159 |
| Sheridan | 161 |
| Sherman | 163 |
| Sioux | 165 |
| Stanton | 167 |
| Thayer | 169 |
| Thomas | 171 |
| Thurston | 173 |
| Valley | 175 |
| Washington | 177 |
| Wayne | 179 |
| Webster | 181 |
| Wheeler | 183 |
| York | 185 |

State Name: **NEVADA**

State Code: 32

| County Name | County Code |
|---|---|
| Churchill | 001 |
| Clark | 003 |
| Douglas | 005 |
| Elko | 007 |
| Esmeralda | 009 |
| Eureka | 011 |
| Humboldt | 013 |
| Lander | 015 |
| Lincoln | 017 |
| Lyon | 019 |
| Mineral | 021 |
| Nye | 023 |
| Ormsby - Independent City of Carson City | 510 |
| Pershing | 027 |
| Storey | 029 |
| Washoe | 031 |
| White Pine | 033 |

State Name: **NEW MEXICO**

State Code: 35

| County Name | County Code |
|---|---|
| Bernalillo | 001 |
| Catron | 003 |
| Chaves | 005 |
| Colfax | 007 |
| Curry | 009 |
| De Baca | 011 |
| Dona Ana | 013 |
| Eddy | 015 |
| Grant | 017 |
| Guadalupe | 019 |
| Harding | 021 |
| Hidalgo | 023 |
| Lea | 025 |
| Lincoln | 027 |
| Los Alamos | 028 |
| Luna | 029 |
| McKinley | 031 |
| Mora | 033 |
| Otero | 035 |
| Quay | 037 |
| Rio Arriba | 039 |
| Roosevelt | 041 |
| Sandoval | 043 |
| San Juan | 045 |
| San Miguel | 047 |
| Santa Fe | 049 |
| Sierra | 051 |
| Socorro | 053 |

# APPENDIX A-5-L

| | |
|---|---|
| Taos | 055 |
| Torrance | 057 |
| Union | 059 |
| Valencia | 061 |

State Name: **OREGON**

State Code: 41

| County Name | County Code |
|---|---|
| Baker | 001 |
| Benton | 003 |
| Clakamas | 005 |
| Clatsop | 007 |
| Columbia | 009 |
| Coos | 011 |
| Crook | 013 |
| Curry | 015 |
| Deschutes | 017 |
| Douglas | 019 |
| Gilliam | 021 |
| Grant | 023 |
| Harney | 025 |
| Hood River | 027 |
| Jackson | 029 |
| Jefferson | 031 |
| Josephine | 033 |
| Klamath | 035 |
| Lake | 037 |
| Lane | 039 |
| Lincoln | 041 |
| Linn | 043 |
| Malheur | 045 |
| Marion | 047 |
| Morrow | 049 |
| Multnomah | 051 |
| Polk | 053 |
| Sherman | 055 |
| Tillamook | 057 |
| Umatilla | 059 |
| Union | 061 |
| Wallowa | 063 |
| Wasco | 065 |
| Washington | 067 |
| Wheeler | 069 |
| Yamhill | 071 |

State Name: **South Dakota**

State Code: 46

| County Name | County Code |
|---|---|
| Aurora | 003 |
| Beadle | 005 |
| Bennett | 007 |
| Bon Homme | 009 |
| Brookings | 011 |
| Brown | 013 |
| Brule | 015 |
| Buffalo | 017 |
| Butte | 019 |
| Campbell | 021 |
| Charles Mix | 023 |
| Clark | 025 |
| Clay | 027 |
| Codington | 029 |
| Corson | 031 |
| Custer | 033 |
| Davison | 035 |
| Day | 037 |
| Deuel | 039 |
| Dewey | 041 |
| Douglas | 043 |
| Edmunds | 045 |
| Fall River | 047 |
| Faulk | 049 |
| Grant | 051 |
| Gregory | 053 |
| Haakon | 055 |
| Hamlin | 057 |
| Hand | 059 |
| Hanson | 061 |
| Harding | 063 |
| Hughes | 065 |
| Hutchinson | 067 |
| Hyde | 069 |
| Jackson | 071 |
| Jerauld | 073 |
| Jones | 075 |
| Kingsbury | 077 |
| Lake | 079 |
| Lawrence | 081 |
| Lincoln | 083 |
| Lyman | 085 |
| McCook | 087 |
| McPherson | 089 |
| Marshall | 091 |
| Meade | 093 |
| Mellette | 095 |
| Miner | 097 |
| Minnehaha | 099 |
| Moody | 101 |
| Pennington | 103 |
| Perkins | 105 |
| Potter | 107 |
| Roberts | 109 |
| Sanborn | 111 |
| Shannon | 113 |
| Spink | 115 |
| Stanley | 117 |
| Sully | 119 |
| Todd | 121 |
| Tripp | 123 |
| Turner | 125 |
| Union | 127 |
| Walworth | 129 |
| Washabaugh | 131 |
| Yankton | 135 |
| Ziebach | 137 |

State Name: **TEXAS**

State Code: 48

| County Name | County Code |
|---|---|
| Anderson | 001 |
| Andrews | 003 |
| Angelina | 005 |
| Aransas | 007 |
| Archer | 009 |
| Armstrong | 011 |
| Atascosa | 013 |
| Austin | 015 |
| Bailey | 017 |
| Bandera | 019 |
| Bastrop | 021 |
| Baylor | 023 |
| Bee | 025 |
| Bell | 027 |
| Bexar | 029 |
| Blanco | 031 |
| Borden | 033 |
| Bosque | 035 |
| Bowie | 037 |
| Brazoria | 039 |

# APPENDIX A-5-L

| | | | | | |
|---|---|---|---|---|---|
| Brazos | 041 | Ector | 135 | Hudspeth | 229 |
| Brewster | 043 | Edwards | 137 | Hunt | 231 |
| Briscoe | 045 | Ellis | 139 | Hutchinson | 233 |
| Brooks | 047 | El Paso | 141 | Irion | 235 |
| Brown | 049 | Erath | 143 | Jack | 237 |
| Burleson | 051 | Falls | 145 | Jackson | 239 |
| Burnet | 053 | Fannin | 147 | Jasper | 241 |
| Caldwell | 055 | Fayette | 149 | Jeff Davis | 243 |
| Calhoun | 057 | Fisher | 151 | Jefferson | 245 |
| Callahan | 059 | Floyd | 153 | Jim Hogg | 247 |
| Cameron | 061 | Foard | 155 | Jim Wells | 249 |
| Camp | 063 | Fort Bend | 157 | Johnson | 251 |
| Carson | 065 | Franklin | 159 | Jones | 253 |
| Cass | 067 | Freestone | 161 | Karnes | 255 |
| Castro | 069 | Frio | 163 | Kaufman | 257 |
| Chambers | 071 | Gaines | 165 | Kendall | 259 |
| Cherokee | 073 | Galveston | 167 | Kenedy | 261 |
| Childress | 075 | Garza | 169 | Kent | 263 |
| Clay | 077 | Gillespie | 171 | Kerr | 265 |
| Cochran | 079 | Glasscock | 173 | Kimble | 267 |
| Coke | 081 | Goliad | 175 | King | 269 |
| Coleman | 083 | Gonzales | 177 | Kinney | 271 |
| Collin | 085 | Gray | 179 | Kleberg | 273 |
| Collingsworth | 087 | Grayson | 181 | Knox | 275 |
| Colorado | 089 | Gregg | 183 | Lamar | 277 |
| Comal | 091 | Grimes | 185 | Lamb | 279 |
| Comanche | 093 | Guadalupe | 187 | Lampasas | 281 |
| Concho | 095 | Hale | 189 | La Salle | 283 |
| Cooke | 097 | Hall | 191 | Lavaca | 285 |
| Coryell | 099 | Hamilton | 193 | Lee | 287 |
| Cottle | 101 | Hansford | 195 | Leon | 289 |
| Crane | 103 | Hardeman | 197 | Liberty | 291 |
| Crockett | 105 | Hardin | 199 | Limestone | 293 |
| Crosby | 107 | Harris | 201 | Lipscomb | 295 |
| Culberson | 109 | Harrison | 203 | Live Oak | 297 |
| Dallam | 111 | Hartley | 205 | Llano | 299 |
| Dallas | 113 | Haskell | 207 | Loving | 301 |
| Dawson | 115 | Hays | 209 | Lubbock | 303 |
| Deaf Smith | 117 | Hemphill | 211 | Lynn | 305 |
| Delta | 119 | Henderson | 213 | McCulloch | 307 |
| Denton | 121 | Hidalgo | 215 | McLennan | 309 |
| DeWitt | 123 | Hill | 217 | McMullen | 311 |
| Dickens | 125 | Hockley | 219 | Madison | 313 |
| Dimmit | 127 | Hood | 221 | Marion | 315 |
| Donley | 129 | Hopkins | 223 | Martin | 317 |
| Duval | 131 | Houston | 225 | Mason | 319 |
| Eastland | 133 | Howard | 227 | Matagorda | 321 |

# APPENDIX A-5-L

| | |
|---|---|
| Maverick | 323 |
| Medina | 325 |
| Menard | 327 |
| Midland | 329 |
| Milam | 331 |
| Mills | 333 |
| Mitchell | 335 |
| Montague | 337 |
| Montgomery | 339 |
| Moore | 341 |
| Morris | 343 |
| Motley | 345 |
| Nacogdoches | 347 |
| Navarro | 349 |
| Newton | 351 |
| Nolan | 353 |
| Neuces | 355 |
| Ochiltree | 357 |
| Oldham | 359 |
| Orange | 361 |
| Palo Pinto | 363 |
| Panola | 365 |
| Parker | 367 |
| Parmer | 369 |
| Pecos | 371 |
| Polk | 373 |
| Potter | 375 |
| Presidio | 377 |
| Rains | 379 |
| Randall | 381 |
| Reagan | 383 |
| Real | 385 |
| Red River | 387 |
| Reeves | 389 |
| Refugio | 391 |
| Roberts | 393 |
| Robertson | 395 |
| Rockwall | 397 |
| Runnels | 399 |
| Rusk | 401 |
| Sabine | 403 |
| San Augustine | 405 |
| San Jacinto | 407 |
| San Patricio | 409 |
| San Saba | 411 |
| Schleicher | 413 |
| Scurry | 415 |
| Shackelford | 417 |
| Shelby | 419 |
| Sherman | 421 |
| Smith | 423 |
| Somervell | 425 |
| Starr | 427 |
| Stephens | 429 |
| Sterling | 431 |
| Stonewall | 433 |
| Sutton | 435 |
| Swisher | 437 |
| Tarrant | 439 |
| Taylor | 441 |
| Terrell | 443 |
| Terry | 445 |
| Throckmorton | 447 |
| Titus | 449 |
| Tom Green | 451 |
| Travis | 453 |
| Trinity | 455 |
| Tyler | 457 |
| Upshur | 459 |
| Upton | 461 |
| Uvalde | 463 |
| Val Verde | 465 |
| Van Zandt | 467 |
| Victoria | 469 |
| Walker | 471 |
| Waller | 473 |
| Ward | 475 |
| Washington | 477 |
| Webb | 479 |
| Wharton | 481 |
| Wheeler | 483 |
| Wichita | 485 |
| Wilbarger | 487 |
| Willacy | 489 |
| Williamson | 491 |
| Wilson | 493 |
| Winkler | 495 |
| Wise | 497 |
| Wood | 499 |
| Yoakum | 501 |
| Young | 503 |
| Zapata | 505 |
| Zavala | 507 |

State Name: **UTAH**

State Code: 49

| County Name | County Code |
|---|---|
| Beaver | 001 |
| Box Elder | 003 |
| Cache | 005 |
| Carbon | 007 |
| Daggett | 009 |
| Davis | 011 |
| Duchesne | 013 |
| Emery | 015 |
| Garfield | 017 |
| Grand | 019 |
| Iron | 021 |
| Juab | 023 |
| Kane | 025 |
| Millard | 027 |
| Morgan | 029 |
| Piute | 031 |
| Rich | 033 |
| Salt Lake | 035 |
| San Juan | 037 |
| Sanpete | 039 |
| Sevier | 041 |
| Summit | 043 |
| Tooele | 045 |
| Uintah | 047 |
| Utah | 049 |
| Wasatch | 051 |
| Washington | 053 |
| Wayne | 055 |
| Weber | 057 |

State Name: **WASHINGTON**

State Code: 53

| County Name | County Code |
|---|---|
| Adams | 001 |
| Asotin | 003 |
| Benton | 005 |
| Chelan | 007 |
| Clallam | 009 |
| Clark | 011 |
| Columbia | 013 |
| Cowlitz | 015 |
| Douglas | 017 |

| | |
|---|---|
| Ferry | 019 |
| Franklin | 021 |
| Garfield | 023 |
| Grant | 025 |
| Grays Harbor | 027 |
| Island | 029 |
| Jefferson | 031 |
| King | 033 |
| Kitsap | 035 |
| Kittitas | 037 |
| Klickitat | 039 |
| Lewis | 041 |
| Lincoln | 043 |
| Mason | 045 |
| Okanogan | 047 |
| Pacific | 049 |
| Pend Oreille | 051 |
| Pierce | 053 |
| San Juan | 055 |
| Skagit | 057 |
| Skamania | 059 |
| Snohomish | 061 |
| Spokane | 063 |
| Stevens | 065 |
| Thurston | 067 |
| Wahkiakum | 069 |
| Walla Walla | 071 |
| Whatcom | 073 |
| Whitman | 075 |
| Yakima | 077 |

State Name: **WYOMING**

State Code: 56

| County Name | County Code |
|---|---|
| Albany | 001 |
| Big Horn | 003 |
| Campbell | 005 |
| Carbon | 007 |
| Converse | 009 |
| Crook | 011 |
| Fremont | 013 |
| Goshen | 015 |
| Hot Springs | 017 |
| Johnson | 019 |
| Laramie | 021 |
| Lincoln | 023 |
| Natrona | 025 |
| Niobrara | 027 |
| Park | 029 |
| Platte | 031 |
| Sheridan | 033 |
| Sublette | 035 |
| Sweetwater | 037 |
| Teton | 039 |
| Uinta | 041 |
| Washakie | 043 |
| Weston | 045 |

AREAS OUTSIDE UNITED STATES

Canada - Use State Code 99
Mexico - Use State Code 88

Organizations outside U.S. leave three digit County code blank.

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# APPENDIX G: ZONE CODES

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# APPENDIX A-5-L

## ZONE CODES

| Zone | Zone to Zone Ties (defines zone boundaries) | | Zone Code |
|---|---|---|---|
| Alberta | | | NWCA |
| | Coleman-Natal 138 kV | NWCA to NWCB | |
| | Langdon-Cranbrook 500 kV | NWCA to NWCB | |
| | Pocaterra-Natal 138 kV | NWCA to NWCB | |
| Arizona | | | AZ |
| | Cholla-Four Corners 345 kV # 1 & 2 | AZ to FCO | |
| | Moeokopi-Four Corners 500 kV | AZ to FCO | |
| | Kayenta-Shiprock 230 kV | AZ to FCO | |
| | Liberty-Blythe 230/161 kV | AZ to IID | |
| | Greenlee-Hildago 345 kV | AZ to NM | |
| | Springerville-Luna 345 kV | AZ to NM | |
| | Springerville-McKinley 345 kV # 1 & 2 | AZ to NM | |
| | Davis-McCullough 230 kV | AZ to NVS | |
| | Davis-Mead 230 kV | AZ to NVS | |
| | Liberty-Mead 345 kV | AZ to NVS | |
| | Moenkipi-Eldorado 500 kV | AZ to NVS | |
| | Navajo-Crystal 500 kV | AZ to NVS | |
| | Perkins-Mead 500 kV | AZ to NVS | |
| | Westwing-Palo Verde 500 kV #1 & 2 | AZ to PV | |
| | Kyrene-Palo Verde 500 kV | AZ to PV | |
| | North Gila 69/500 kV | AZ to PV | |
| | Glen Canyon-Sigurd 230 kV | AZ to UT | |
| British Columbia | | | NWCB |
| | Cranbrook-Langdon 500 kV | NWCB to NWCA | |
| | Natal-Coleman 138 kV | NWCB to NWCA | |
| | Natal-Pocaterra 138 kV | NWCB to NWCA | |
| | Ingledow-Custer 500 kV # 1 & 2 | NWCB to NWUW | |
| | Waneta-Boundary 230 kV | NWCB to NWUW | |
| | Nelway-Boundary 230 kV | NWCB to NWUW | |
| California, Central | | | PGES |
| | Gates-Panoche 230 kV # 1 & 2 | PGES to PGEN | |
| | Midway-Los Banos 500 kV # 1 & 2 | PGES to PGEN | |
| | Gates-Mc Call 230 kV | PGES to PGEN | |
| | Gates-Gregg 230 kV | PGES to PGEN | |
| | Midway-Vincent 500 kV # 1, 2, & 3 | PGES to SCE | |
| California, IID | | | IID |
| | Blythe-Liberty 161/230 kV | IID to AZ | |
| | Imperial Valley 230/500 kV | IID to PV | |
| | Coachella-Devers 230 kV | IID to SCE | |

| | | | |
|---|---|---|---|
| | Coachella-Mirage 230 kV | IID to SCE | |
| California, LDWP | | | LDWP |
| | Adelanto-Marketplace 500 kV | LDWP to NVS | |
| | Victorville-Mead 230 kV | LDWP to NVS | |
| | Victorville-McCullough 500 kV # 1 & 2 | LDWP to NVS | |
| | Sylmar-The Dalles ±500 kV DC | LDWP to NWUW | |
| | McCullough-Eldorado 500 kV | LDWP to SCE | |
| | Victorville-Lugo 500 kV | LDWP to SCE | |
| | Sylmar LDWP/Sylmar SCE bus | LDWP to SCE | |
| | Inyo-Control 230 kV | LDWP to SCE | |
| | Adelanto-Intermountain ±500 kV DC | LDWP to UT | |
| California, North | | | PGEN |
| | Round Mountain-Malin 500 kV # 1 & 2 | PGEN to COB | |
| | Olinda-Captain Jack 500 kV | PGEN to COB | |
| | COPCO-Meridian 230 kV | PGEN to COB | |
| | COPCO-J C boyle 230 kV | PGEN to COB | |
| | Drum-Summit 115 kV # 1 & 2 | PGEN to NVN | |
| | Drum-Summit 60 kV | PGEN to NVN | |
| | Martin-San Mateo 230 kV | PGEN to PGEP | |
| | Martin-San Mateo 115 kV | PGEN to PGEP | |
| | SFIA-San Mateo 115 kV | PGEN to PGEP | |
| | Panoche-Gates 230 kV # 1 & 2 | PGEN to PGES | |
| | Gregg-Gates 230 kV | PGEN to PGES | |
| | Los Banos-Midway 500 kV #1 & 2 | PGEN to PGES | |
| | McCall-Gates 230 kV | PGEN to PGES | |
| | various | PGEN to SMUD | |
| California, San Diego | | | SDGE |
| | Imperial Valley 500/230 kV | SDGE to IID | |
| | Miguel-Tijuana 230 kV | SDGE to MXW | |
| | Imperial Valley-Rosita 230 kV | SDGE to MXW | |
| | Imperial Valley-North Gila 500 kV | SDGE to PV | |
| | Encina-San Onofre 230 kV | SDGE to SCE | |
| | Mission-San Onofre 230 kV | SDGE to SCE | |
| | Talega-San Onofre 230 kV # 1 & 2 | SDGE to SCE | |
| California, San Francisco | | | PGEP |
| | San Mateo-Martin 230 kV | PGEP to PGEN | |
| | San Mateo-Martin 115 kV | PGEP to PGEN | |
| | San Mateo-SFIA 115 kV | PGEP to PGEN | |
| California, SMUD | | | SMUD |
| | various | SMUD to PGEN | |

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| | | | |
|---|---|---|---|
| California, South | | | SCE |
| | Devers-Coachella 230 kV | SCE to IID | |
| | Mirage-Coachella 230 kV | SCE to IID | |
| | Eldorado-McCullough 500 kV | SCE to LDWP | |
| | Lugo-Victorville 500 kV | SCE to LDWP | |
| | Sylmar SCE/Sylmar LDWP bus | SCE to LDWP | |
| | Control-Inyo 230 kV | SCE to LDWP | |
| | Lugo-Eldorado 500 kV | SCE to NVS | |
| | Lugo-Mohave 500 kV | SCE to NVS | |
| | Pisgh-Eldorado 230 kV # 1 & 2 | SCE to NVS | |
| | Camino-Mead 230 kV # 1 & 2 | SCE to NVS | |
| | Control-Silver Peak 55 kV # 1 & 2 | SCE to NVN | |
| | Vincent-Midway 500 kV # 1, 2, & 3 | SCE to PGES | |
| | Devers-Palo Verde 500 kV | SCE to PV | |
| | San Onofre-Encina 230 kV | SCE to SDGE | |
| | San Onofre-Mission 230 kV # 1 & 2 | SCE to SDGE | |
| | San Onofre-Talega 230 kV # 1 & 2 | SCE to SDGE | |
| CFE-Mexico | | | MXW |
| | Tijuana-Miguel 230 kV | MXW to SDGE | |
| | Rosita-Imperial Valley 230 kV | MXW to SDGE | |
| COB | | | COB |
| | Malin-Bordertown 345 kV | COB to NVN | |
| | Malin-Grizzly 500 kV | COB to NWUW | |
| | Captain Jack-Grizzly 500 kV | COB to NWUW | |
| | Captain Jack Meridian 500 kV | COB to NWUW | |
| | Malin-Klamath Falls 230 kV | COB to NWUW | |
| | Malin-Summer Lake 500 kV | COB to NWUW | |
| | Malin-Round Mountain 500 kV # 1 & 2 | COB to PGEN | |
| | Captain Jack-Olinda 500 kV | COB to PGEN | |
| | Meridian-COPCO 230 kV | COB to PGEN | |
| | J C Boyle-COPCO 230 kV | COB to PGEN | |
| Colorado, East | | | COE |
| | Archer-Hayden 230 kV | COE to COW | |
| | Ault-Craig 345 kV | COE to COW | |
| | Dillon-Gore Pass 230 kV | COE to COW | |
| | Malta-Hopkins 230 kV | COE to COW | |
| | Poncha-Curecanti 230 kV | COE to COW | |
| | Archer-Stegall 230 kV | COE to WY | |
| | Ault-Laramie River 345 kV | COE to WY | |
| | North Yuma-Sidney 230 kV | COE to WY | |
| | Story-Laramie River 345 kV | COE to WY | |
| | Sterling-Sidney 115 kV | COE to WY | |
| | Timberline-Cheyenne 115 kV | COE to WY | |

# APPENDIX A-5-L

| | | | |
|---|---|---|---|
| Colorado, West | | | COW |
| | Hayden-Archer 230 kV | COW to COE | |
| | Craig-Ault 345 kV | COW to COE | |
| | Gore Pass-Dillon 230 kV | COW to COE | |
| | Hopkins-Malta 230 kV | COW to COE | |
| | Curecanti-Poncha 230 kV | COW to COE | |
| | Lost Canyon-Shiprock 230 kV | COW to FCO | |
| | Durango-Farmington 115 kV | COW to FCO | |
| | Waterflow-San Juan 345 kV | COW to FCO | |
| | Bears Ears-Bonanza 345 kV | COW to UT | |
| | Hayden-Artesia 138 kV | COW to UT | |
| | Rangely-Artesia 138 kV | COW to UT | |
| | Rangely-Bonanza 138 kV | COW to UT | |
| Four Corners | | | FCO |
| | Four Corners-Cholla 345 kV # 1 & 2 | FCO to AZ | |
| | Four Corners-Moenkopi 500 kV | FCO to AZ | |
| | San Juan-McKinley 345 kV # 1 & 2 | FCO to AZ | |
| | Shiprock-Kayenta 230 kV | FCO to AZ | |
| | Shiprock-Lost Canyon 230 kV | FCO to COW | |
| | Farmington-Durango 115 kV | FCO to COW | |
| | San Juan-Waterflow 345 kV | FCO to COW | |
| | Four Corners-West Mesa 345 kV | FCO to NM | |
| | San Juan-B–A 345 kV | FCO to NM | |
| | San Juan-Ojo 345 kV | FCO to NM | |
| | Bisti-Ambrosia 230 kV | FCO to NM | |
| | Four Corners-Pinto 345 kV | FCO to UT | |
| Idaho | | | ID |
| | Antelope-Peterson Flats 230 kV | ID to MT | |
| | Big Grassy-Dillon 161 kV | ID to MT | |
| | Midpoint-Humboldt 345 kV | ID to NVN | |
| | King-Wells 115 kV | ID to NVN | |
| | Midpoint-Burns 500 kV | ID to NWUW | |
| | Brownlee-Quartz Tap 230 kV | ID to NWUW | |
| | Oxbow-Lolo 230 kV | ID to NWUW | |
| | Hells Canyon-Enterprise 230 kV | ID to NWUW | |
| | Borah-Ben Lomond 345 kV | ID to UT | |
| | Brady-Treasureton 230 kV | ID to UT | |
| | Goshen-Grace 161 kV | ID to UT | |
| | American Falls-Malad 138 kV | ID to UT | |
| | Borah-Jim Bridger 345 kV | ID to WY | |
| | Goshen-Jim Bridger 345 kV | ID to WY | |
| | Kinport-Jim Bridger 345 kV | ID to WY | |
| Montana | | | MT |
| | Peterson Flats-Antelope 230 kV | MT to ID | |

| | | | |
|---|---|---|---|
| | Dillon-Big Grassy 115 kV | MT to ID | |
| | Broadview-Garrison 500 kV # 1 & 2 | MT to NWUW | |
| | Ovando-Garrison 230 kV | MT to NWUW | |
| | Ovando-Hot Springs 230 kV | MT to NWUW | |
| | Rattlesnake 230/161 kV | MT to NWUW | |
| | Kerr-Elmo 115 kV | MT to NWUW | |
| | Thompson Falls-Burke 115 kV | MT to NWUW | |
| | Crow Creek-Burke 115 kV | MT to NWUW | |
| | Billings-Yellowtail 230 kV | MT to WY | |
| | Rimrock-Yellowtail 161 kV | MT to WY | |
| | Crossover-Yellowtail 230 kV | MT to WY | |
| Nevada, North | | | NVN |
| | Bordertown-Malin 345 kV | NVN to COB | |
| | Humboldt-Midpoint 345 kV | NVN to ID | |
| | Wells-King 115 kV | NVN to ID | |
| | Summit-Drum 115 kV # 1 & 2 | NVN to PGEN | |
| | Summit-Drum 60 kV | NVN to PGEN | |
| | Silver Peak-Control 55 kV # 1 & 2 | NVN to SCE | |
| | Gonder-Intermountain 230 kV | NVN to UT | |
| | Gonder-Pavant 230 kV | NVN to UT | |
| Nevada, South | | | NVS |
| | Crystal-Navajo 500 kV | NVS to AZ | |
| | Eldorado-Moenkopi 500 kV | NVS to AZ | |
| | McCullough-Davis 230 kV | NVS to AZ | |
| | Mead-Davis 230 kV | NVS to AZ | |
| | Mead-Peacock 345 kV | NVS to AZ | |
| | Mead-Perkins 500 kV | NVS to AZ | |
| | Marketplace-Adelanto 500 kV | NVS to LDWP | |
| | McCullough-Victorville 500 kV # 1 & 2 | NVS to LDWP | |
| | Mead-Victorville 230 kV | NVS to LDWP | |
| | Eldorado-Lugo 500 kV | NVS to SCE | |
| | Mohave-Lugo 500 kV | NVS to SCE | |
| | Eldorado-Pisgh 230 kV # 1 & 2 | NVS to SCE | |
| | Mead-Camino 230 kV # 1 & 2 | NVS to SCE | |
| | Harry Allen-Redbutte 345 kV | NVS to UT | |
| New Mexico | | | NM |
| | Hidalgo-Greenlee 345 kV | NM to AZ | |
| | Luna-Springerville 345 kV | NM to AZ | |
| | Yah-Ta-Hey-McKinley 345 kV | NM to AZ | |
| | West Mesa-Four Corners 345 kV | NM to FCO | |
| | B–A-San Juan 345 kV | NM to FCO | |
| | Ojo-San Juan 345 kV | NM to FCO | |
| | Ambrosia-Bisti 230 kV | NM to FCO | |

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| | | | |
|---|---|---|---|
| Northwest | | | NWUW |
| | Grizzly-Malin 500 kV | NWUW to COB | |
| | Grizzly-Captain Jack 500 kV | NWUW to COB | |
| | Meridian-Captain Jack 230 kV | NWUW to COB | |
| | Klamath Falls-Malin 500 kV | NWUW to COB | |
| | Summer Lake-Malin 500 kV | NWUW to COB | |
| | Burns-Midpoint 500 kV | NWUW to ID | |
| | LaGrande-Brownlee 230 kV | NWUW to ID | |
| | Quartz-Brownlee 230 kV | NWUW to ID | |
| | Enterprise-Hells Canyon 230 kV | NWUW to ID | |
| | Garrison-Broadview 500 kV # 1 & 2 | NWUW to MT | |
| | Garrison-Ovando 230 kV | NWUW to MT | |
| | Hot Springs-Ovando 230 kV | NWUW to MT | |
| | Rattlesnake 161/230 kV | NWUW to MT | |
| | Elmo-Kerr 115 kV | NWUW to MT | |
| | Burke-Thompson Falls 115 kV | NWUW to MT | |
| | Burke-Crow Creek 115 kV | NWUW to MT | |
| | Custer-Ingledow 500 kV # 1 & 2 | NWUW to NWCB | |
| | Boundary-Nelway 230 kV | NWUW to NWCB | |
| | Boundary-Waneta 230 kV | NWUW to NWCB | |
| Palo Verde | | | PV |
| | Palo Verde-Westwing 500 kV # 1 & 2 | PV to AZ | |
| | Palo Verde-Kyrene 500 kV | PV to AZ | |
| | North Gila 500/69 kV | PV to AZ | |
| | Imperial Valley 500/230 kV | PV to IID | |
| | Palo Verde-Devers 500 kV | PV to SCE | |
| | North Gila-Imperial Valley 500 kV | PV to SDGE | |
| Utah | | | UT |
| | Sigurd-Glenn Canyon 230 kV | UT to AZ | |
| | Bonanza-Bears Ears 345 kV | UT to COW | |
| | Artesia-Hayden 138 kV | UT to COW | |
| | Artesia-Rangely 138 kV | UT to COW | |
| | Bonanza-Rangely 138 kV | UT to COW | |
| | Pinto-Four Corners 345 kV | UT to FCO | |
| | Ben Lomond-Borah 345 kV | UT to ID | |
| | Treasureton-Brady 230 kV | UT to ID | |
| | Grace-Goshen 161 kV | UT to ID | |
| | Malad-American Falls 138 kV | UT to ID | |
| | Intermountain-Adelanto ±500 kV | UT to LDWP | |
| | Intermountain-Gonder 230 kV | UT to NVN | |
| | Pavant-Gonder 230 kV | UT to NVN | |
| | Redbutte-Harry Allen 345 kV | UT to NVS | |
| | Naughton-Monument 230 kV | UT to WY | |
| | Flaming Gorge-Firehole 230 kV | UT to WY | |

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| | | |
|---|---|---|
| Wyoming | | WY |
| | Stegall-Archer 230 kV | WY to COE |
| | Laramie River-Ault 345 kV | WY to COE |
| | Laramie River-Story 345 kV | WY to COE |
| | Sidney-Sterling 115 kV | WY to COE |
| | Cheyenne-Timberline 115 kV | WY to COE |
| | Jim Bridger-Borah 345 kV | WY to ID |
| | Jim Bridger-Goshen 345 kV | WY to ID |
| | Jim Bridger-Kinport 345 kV | WY to ID |
| | Naughton-Treasureton 230 kV | WY to ID |
| | Yellowtail-Billings 230 kV | WY to MT |
| | Yellowtail-Rimrock 161 kV | WY to MT |
| | Yellowtail-Crossover 230 kV | WY to MT |
| | Monument-Naughton 230 kV | WY to UT |
| | Firehole-Flaming Gorge 230 kV | WY to UT |

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# APPENDIX A-5-L

**APPENDIX H: Exhibit B – Collection and Review of Loads and Resources Data**

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**Exhibit B[i] – Collection and Review of Loads and Resources Data**

**A. Overview and Background.**

The WECC Loads and Resources Subcommittee (LRS) oversees the WECC loads and resources data collection and power supply assessment for the resource adequacy in WECC. The LRS is the primary WECC forum that addresses the loads and resources activities at NERC. The LRS is also the primary WECC entity disseminating information to all parties within the Western Interconnection as it relates to load and resources. Data collected by the LRS may also be incorporated into the Transmission Expansion Planning Policy Committee Database for regional and sub-regional studies.

LRS responsibilities also include:

- developing and recommending resource adequacy guidelines and targets to the Planning Coordination Committee for the power supply assessment;
- developing approaches that will promote compilation of loads and resources data that are clear, comprehensive, and accurate;
- developing meaningful processes for assessing resource adequacy (capacity and energy) and reporting the results of such assessments;
- preparing and presenting reports of the data received from WECC entities, including aggregations of confidential data that are suitable for release to the public; and
- other duties as directed by the Planning Coordination Committee.

**B. Identification of Exhibit B Data Collected by the LRS.**

In accordance with the WECC Reliability Information Sharing Policy, the WECC balancing authorities, load-serving entities or other stakeholders are requested to provide to WECC staff and/or the LRS and update as necessary the data in the general categories listed below (which are referred to elsewhere in this document as "Exhibit B Data"). Section F of this document describes the process for identifying more specifically the data to be submitted from these categories:

- existing generation and transmission data;
- actual year resources data;
- generation additions data;
- future year peak demands, future resources, future scheduled outages, future transfers, and planning reserves data;
- future year demand reduction impacts;
- future year energy load data;
- future year transmission data;
- actual year peak demands, outages, and transfers data;
- actual year demand reduction data;
- actual year energy load data; and

- other data collected in support of the annual Power Supply Assessment process.

**C. Access to Loads and Resources Data by the LRS Members and WECC Staff.**

1. **Confidentiality.** The following information will be treated as confidential under the "WECC Reliability Information Sharing Policy, Section D – Protecting Confidential, Privileged, and Proprietary Information" (approved by the Board on December 1, 2005): first three years of future data on projected peak demand, energy load, and scheduled outages. These data will remain confidential for three years from the date of designation, after which the data will become non-confidential. Future year peak demands, future year energy load, and future year scheduled outages data beyond three years will ***not*** be deemed confidential.

2. **Access to Data by LRS Members and WECC Staff.** The LRS chair will designate LRS members who are authorized to be active participants in LRS data or adequacy analysis task forces. These designated LRS members and WECC staff may obtain and review:

   - all Exhibit B Data;
   - other data obtained from supplemental data requests for use in the annual power supply assessment process and other assessments required by NERC; and
   - results of the annual power supply assessment.

   LRS members designated by the LRS chair to be given access to confidential Exhibit B Data must not be involved in trading or marketing activities and must be transmission function or shared employees (as defined by Standards of Conduct filings submitted to FERC by jurisdictional utilities in the U.S. or Standards of Conduct filings submitted to provincial authorities for Canadian utilities). Class 5 WECC members and members based outside the U.S. that are not subject to Standard of Conduct and are not involved in marketing or trading activities may be given access by the LRS chair.

   Members designated by the LRS chair as having access to Exhibit B Data will be re-designated annually and these members will be listed on the website. Further, these members will report any change in their status under applicable Standards of Conduct filings.

   Data to be treated as confidential in accordance with Section C.1 of this document will be used only for the purpose of assessing reliability and adequacy. For the first three years following designation, confidential Exhibit B Data may be accessed only after a WECC confidentiality agreement has become effective pursuant to Section D.2.2.3 of the WECC Reliability Information Sharing Policy. A person or entity that is denied access to Exhibit B Data covered by Section C.1 may appeal this decision to the WECC

Board of Directors as specified in the WECC Reliability Information Sharing Policy and the WECC Bylaws.

3. **Release of Aggregated Versions of Confidential Data.** For Exhibit B Data that is to be treated as confidential in accordance with Section C.1, the LRS is obligated to develop aggregated totals for the first three years of the forecast period that will allow the data to be released to the public without identification of individual member data and end user values.

**D. Disagreements.** Any disagreements about any Exhibit B Data requests or members having access to confidential data as designated by the LRS chair will be resolved through WECC review processes specified in the WECC Reliability Information Sharing Policy.

**E. Critical Energy Infrastructure Information**. None of the Exhibit B Data will be treated as Critical Energy Infrastructure Information unless specifically identified otherwise in an Exhibit to the WECC Reliability Information Sharing Policy.

**F. Specific Data**. Exhibit B Data will be identified more specifically in the "*WECC Reporting Process for the Collection of Loads and Resources Data*" that is adopted annually by the LRS. In addition, any supplemental data requests containing data subject to Section C.1 to support the annual Power Supply Assessment prepared and issued by the WECC staff will be considered Exhibit B Data following review and approval of such data requests by the LRS.

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[i] Exhibit B may require more changes after the NERC reliability and data reporting standards are finalized and approved by FERC in 2007.

# APPENDIX A-5-L