L O S   A N G E L E S   D E P A R T M E N T   O F   W A T E R   A N D   P O W E R

2012 GRID RELIABILITY REPORT

PREPARED FOR CALIFORNIA STATE WATER RESOURCES CONTROL BOARD

DECEMBER 31, 2012 SUBMITTAL

Redacted Version – November 2012

[redacted]

2012 Grid Reliability Report

PREPARED FOR CALIFORNIA STATE WATER RESOURCES CONTROL BOARD

TABLE OF CONTENTS

[redacted]

2012 Grid Reliability Report

PREPARED FOR CALIFORNIA STATE WATER RESOURCES CONTROL BOARD

LIST OF APPENDICES

[redacted]

ACRONYMS AND ABBREVIATIONS

Acronym/Abbreviation	Meaning
AGC	Automatic Generation Control
BAL	NERC Resource and Demand Balancing Standards
Basin	Los Angeles Basin
CaISO	California Independent System Operator
CARB	California Air Resources Board
Castaic	Castaic Power Plant
CIP	NERC Critical Infrastructure Protection Standards
City	City of Los Angeles
COM	NERC Communications Standards
CTPG	California Transmission Planning Group
DG	Distributed Generation
ECC	LADWP’s Energy Control Center
EOP	NERC Emergency Preparedness and Operations Standards
FAC	NERC Facilities Design, Connections, and Maintenance Standards
INT	NERC Interchange Scheduling and Coordination Standards
IPP	Intermountain Power Project
IPPDC	Intermountain Power Project High-Voltage DC Line
IRO	NERC Interconnection Reliability Operations and Coordination Standards
IRP	LADWP’s Integrated Resource Plan
KEMA	KEMA, Inc
kV	kilovolt
LADWP	City of Los Angeles Department of Water and Power
LCR	Local Capacity Requirement
MOD	NERC Modeling, Data, and Analysis Standards
MW	MegaWatt
MWh	MegaWatt-hour
NERC	North American Electric Reliability Corporation
NUC	NERC Nuclear Standards
OTC	Once-Through-Cooling

PDCI	Pacific High-Voltage DC Intertie
PER	NERC Personnel Performance, Training, and Qualifications Standards
PRC	NERC Protection and Control Standards
RMR	Reliability Must-Run
ROW	Right-of-Way
RPS	Renewable Portfolio Standard
SCAB	South Coast Air Basin
SCPPA	Southern California Public Power Authority
STS	IPP's Southern Transmission System
TOP	NERC Transmission Operations Standards
TPL	NERC Transmission Planning Standards
VAR	NERC Voltage and Reactive Standards
WECC	Western Electricity Coordinating Council

[redacted]

2012 Grid Reliability Report

PREPARED FOR CALIFORNIA STATE WATER RESOURCES CONTROL BOARD

OVERVIEW

Electric utilities are complex entities confronted with an ever-changing array of challenges-operational, financial, and regulatory. These challenges must be met while the utility fulfills its primary purpose of delivering reliable power.

To that end, LADWP routinely forecasts short- and long-term demand for electricity, identifies generating sources, and conducts studies to demonstrate to regulatory agencies the reliability of its system under different demand and operational scenarios. Nine years out, as cited in the attached 2012 Grid Reliability Report, high- and mid-load power scenarios already project the need-in 2021- for more generation in the Los Angeles Basin than is expected to be present. The Local Capacity Requirement (LCR) study referenced herein suggests that Los Angeles can ill-afford to have any of its basin (local) generating units unavailable.

Local Units/Plants Are Key to Reliability

The LADWP has negotiated a once-through-cooling (OTC) compliance schedule that does not retire any of its **local** OTC generating units, without first having equivalently-sized, **locationally-equivalent** replacements ready to be placed in-service. It is an aggressive and ambitious schedule that **maintains needed local generation capacity** and system reliability for LADWP's unique system configuration. Given that it is predicated upon a seamless execution of each element of the OTC repowering process, this is the *shortest possible* schedule. Truncating it would affect system reliability.

San Onofre Demonstrates Cul-de-Sac Effect

The ongoing outage at the San Onofre Nuclear Generating Station (SONGS), clearly demonstrates how and why generation location is critical to system reliability. The California Independent System Operator's (CAISO's) local capacity in the Orange County/San Diego area was reduced when the SONGS plant was unexpectedly shut down in January 2012. The loss of SONGS' 2,200 MegaWatts of power (enough to serve about 1.4 million homes) has required state officials to develop contingency plans to avoid summer outages. To compensate for the lost capacity and voltage support, mothballed OTC units at the AES Huntington Beach plant were brought back on line and CAISO requested LADWP's assistance. LADWP is able to assist with a *general* CAISO capacity shortage, but cannot help when there is a *locational* shortage in the southern portion of the CAISO system. This is because the congested transmission paths limit the CAISO from relying heavily on power

[redacted]

generated outside the SDG&E and SCE systems that would usually be served by SONGS.

SONGS illustrates the type of emergency that requires maintenance of local capacity at all times - including some additional reserve capacity, to meet grid reliability requirements. LADWP is confronted with the same limited ability to rely broadly upon other, non-LADWP generation sources. This is why energy efficiency within our system, non-dispatchable renewable energy, demand response, and even generation from our closest in-basin plant cannot meet the same locational supply needs as our coastal generating plants. LADWP has factored its worst case contingencies into its planning process, as required by NERC standards. The Amended OTC Policy 2029 date is absolutely necessary, as it provides adequate time for the integration of energy policies and allows for the elimination of OTC- without sacrificing locational capacity and grid reliability.

<u>Facts:</u>

<u>Role of In-Basin Coastal Units</u>

Begun more than 70 years ago, LADWP's system was "built out" from its three coastal plants, Harbor, Haynes, and Scattergood, which now have a total of nine (9) individual generating units utilizing once-through-cooling (OTC), down from the fourteen (14) original units. As the system backbone, these units provide critical functions, including off-loading of the local transmission circuits and voltage control. If the OTC units were not available during certain operating conditions that can occur throughout the year, the LADWP system could not function: the transmission lines could become overloaded potentially requiring the disconnection of customers to avoid damaging the system. The OTC units also provide voltage support and stability to the entire system, thus enabling the importation of power supplies (61% of total power) from outside the Los Angeles basin. This is an ironic result of the system configuration. While the OTC units *enable* power importation, the intra-city transmission system's capacity limitations prevent *delivery* of sufficient imported power to the western and southern portions of LADWP's service territory, which are situated in power "cul-de-sacs." As there is no land for adding new, or making substantial upgrades to, the existing local transmission lines, the OTC units are therefore the "sole source" suppliers for the cul-de-sacs once available transmission is utilized.

LADWP is in the process of integrating variable (renewable) energy resources (VERS) into its system to meet the state mandate for 33% renewable power by 2020. The OTC units are critical to meeting system demand when the VERS are not generating power, or when VERS power output decreases and/or fluctuates rapidly.

Lack of sufficient space at the coastal plants precludes the installation of the new, closed-cycle (non-OTC) units (repowering) *while* the existing OTC units continue to operate. This unprecedented, large-scale conversion away from OTC units must therefore be carefully planned and executed sequentially, plant-by-plant, unit-by-unit. to protect system reliability and ensure the delivery of power to LADWP's 1.4 million retail electric customers.

[redacted]

LADWP: Vertically-Integrated Utility

LADWP is a vertically-integrated utility with a 465 square mile service territory that owns and operates its own generation, transmission and distribution systems. LADWP is not part of the California Independent System Operator (CAISO), which manages electricity flow for 80 percent of the state. LADWP's grid Interconnections, which import/export energy from other western utilities, are located outside Los Angeles or at its extreme northern edge. However, the availability of these interconnections does not change LADWP's generation reliability requirements. This is because LADWP does not rely on the energy market or other transmission system operators as the primary means to meet its power needs.

Compliance Schedule

Per the negotiated compliance schedule approved by the State Water Resources Control Board, LADWP will be continuously undertaking repowering projects continuously through 2029. LADWP has already reduced its OTC units from 14 to 9, and the repowering of Haynes Units 5&6 with dry cooling will be completed by 2013. To maximize OTC reduction, LADWP also revised the Scattergood Generating Station repowering sequence to replace the largest OTC unit first, for an extra 10% overall OTC reduction.

Schedule Predicated Upon Best-Case Scenario

The schedule allocates the *minimum* amount of time for each of the very complex tasks necessary for repowering, including: conceptual engineering; air emissions modeling; demolition; obtaining permits from the South Coast Air Quality Management District; and the construction, commissioning and trial operations of new units. The new units are an essential part of LADWP's system, yet the compliance schedule allows a much shorter than usual schedule for unit commissioning and trial operations.

In addition, execution of the schedule necessarily involves other parties, including the LADWP Board of Water and Power Commissioners, the 15 member Los Angeles City Council, outside vendors, manufacturers, and/or regulatory agencies. For example, LADWP must obtain City Council approval before a Request for Proposal or a Contract for design, equipment procurement, engineering and/or construction services can be awarded. Obtaining an air permit for the construction of new units takes approximately 12 months- in theory. However, the air permitting for LADWP's Haynes Unit 5&6 repower project took a solid two years. This is because new regulations were promulgated by EPA during the permit preparation process, which required additional time for analysis and negotiations with the regulatory agencies.

Conclusion

The SONGS example demonstrates the criticality of LADWP's in-basin OTC units. Lack of physical space at the in-basin plants precludes the removal of the OTC units until their equivalents are installed. This, in turn, leads to the conclusion that the 2029 compliance date found in the Amended OTC Policy is absolutely necessary to maintain locational capacity and grid reliability.

Appendix 6 provides common questions and answers regarding reliability.

[redacted]

2012 Grid Reliability Report

PREPARED FOR CALIFORNIA STATE WATER RESOURCES CONTROL BOARD

BACKGROUND

On October 1, 2010, the California State Water Resources Control Board's (SWRCB's) Resolution 2010-0020, the statewide "Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling" (OTC Policy), became fully effective. This OTC Policy implements Section 316(b) of the Federal Water Pollution Control Act (Clean Water Act) to reduce impingement mortality (IM) and entrainment (E) of marine life caused by the use of estuarine and/or ocean water for cooling at coastal power plants. The OTC Policy allows for two compliance tracks. Track 1 requires ocean water intake flow rate to be reduced by at least 93% at each unit compared to the unit's intake design rate, commensurate with closed-cycle wet cooling systems. Similarly, the intake velocity at each unit must not exceed 0.5 feet per second. Where it can be demonstrated that Track 1 is not feasible, the OTC Policy provides for a Track 2. Track 2 compliance reduces IM and E by at least 90% of Track 1's requirement or at least 83.7%.

All California coastal power plants are impacted by the OTC Policy, including Harbor, Haynes, and Scattergood Generating Stations which are owned and operated by the City of Los Angeles (City) Department of Water and Power (LADWP). The OTC Policy requires the owners and operators of these coastal plants to file by April 1, 2011 implementation plans specifying their intended compliance track and proposed compliance date.

By the April 1st deadline LADWP complied with the OTC Policy by submitting its Track 1 implementation plan to the SWRCB. LADWP proposed to eliminate the use of ocean water by replacing the ocean water cooling intake structures at its three coastal plants to closed-cycle cooling so no seawater would be taken in or discharged by the plants. This technology exceeds the OTC Policy's threshold requirement of a 93% reduction in intake flow rate for each repowered unit.

Since April 1st, an Amendment concerning LADWP's proposed compliance schedule has been adopted and approved. Resolution 2011-0033, fully approved and filed on May 17, 2012 by the SWRCB, amends LADWP's compliance schedule as shown in Table 1:

[redacted]

TABLE 1. LADWP'S COMPLIANCE SCHEDULE

Generating Station	Generating Unit	New Compliance Deadline
Harbor	Unit 5	31 Dec 2029
Haynes	Unit 1	31 Dec 2029
	Unit 2	31 Dec 2029
	Unit 5	31 Dec 2013
	Unit 6	31 Dec 2013
	Unit 8	31 Dec 2029
Scattergood	Unit 1	31 Dec 2024
	Unit 2	31 Dec 2024
	Unit 3	31 Dec 2015

Each December 31st until the coastal power plants within their Balancing Authority Areas (BAAs) comply with the OTC Policy, the California Independent System Operator (CaISO) and LADWP are to file grid reliability studies for their respective jurisdictions; the other eight BAAs in California do not contain coastal plants. Accordingly, LADWP has submitted a Grid Reliability Report in 2010 and 2011 by that year's end. Those reports showed every local generating plant, including its three coastal plants, are classified as Reliability Must Run (RMR) for good reason: the local capacity available from those plants have been deemed necessary to maintain local reliability. More than that, with all the in-basin generation available, dropping some customer load, which are localized and controlled blackouts, may still be necessary under certain conditions.

This "2012 Grid Reliability Report" (2012 Report) updates the "2011 Grid Reliability Report" (2011 Report) using new information developed. These include the "Transmission Reliability Assessment for Summer 2012" dated June 27, 2012, the "2021 Local Capacity Technical Analysis" report (LCT Report) prepared for the California Air Resources Board in February 2012, and the "2011 Ten-Year Transmission Assessment" released in October 2011.

STATE POLICY GOALS

Environmental stewardship is one of LADWP's corporate pillars. As such, LADWP is making steady and significant progress toward upholding all statewide environmental policies by the 2020 target year. In 2012, LADWP's Board of Commissioners (Commissioners) established a number of policy targets to align with these statewide goals. These recent policies are currently being translated into programs, the desired effects of which will be incorporated in LADWP's reports beginning with the 2012 Integrated Resource Plan, 2013 Ten-Year Transmission Assessment, and 2013 Load Forecast which will be presented in future filings. This 2012 Report will point out how the statewide policies are being supported in the studies comprising this report.

The statewide goals as they relate to LADWP are:

- ☐ 33% of LADWP's retail load is satisfied with renewable energy by 2020, with interim goals of 20% by 2013 and 25% by 2016 (SBX1-2 chaptered on April 12, 2011).

- ☐ Greenhouse gas emissions from LADWP's power plants are reduced to 1990 levels by 2020 to assist the State of California in reducing overall statewide emissions (AB32 chaptered on September 27, 2006).

- ☐ The California Energy Commission has established the 1100 lb CO_2 per megawatt-hour emissions standard for any new investments in utility-owned base-load generating plants or long-term power purchase agreements for base-load generation (SB1368, chaptered on September 29, 2006).

- ☐ LADWP meets annual energy efficiency targets established under AB2021 (chaptered on September 29, 2006) in collaboration with the California Energy Commission such that the statewide goal of 13.2 to 18 terawatt-hours in reductions are met by 2020 (California's Clean Energy Future dated September 21, 2010).

- ☐ LADWP makes an acceptable contribution toward California's Clean Energy Future 2020 goal of 5 gigawatts of installed localized generation capacity (or Governor Brown's 2020 goal of 12 gigawatts). The installed localized generation capacity would include an acceptable contribution toward California's 750 MegaWatt Feed-in-Tariff (FiT) Program (SB32 chaptered on October 11, 2009).

- ☐ LADWP makes an acceptable contribution toward the California Air Resources Board's (CARB's) AB32 Scoping Plan 2020 goal of 4 gigawatts of combined heat and power facility (CHP, aka cogeneration) development (CARB's "Climate Change Scoping Plan" dated December 2008) and Governor Brown's 2030 goal of 6.5 gigawatts.

- ☐ LADWP is interconnecting to its transmission system renewable projects to satisfy the renewable portfolio standard.

- ☐ LADWP implements a high-priority demand response program that, where feasible, relieves transmission thermal overloads and/or system stability consequences of credible contingencies.

2012 Reliability Report

PREPARED FOR CALIFORNIA STATE WATER RESOURCES CONTROL BOARD

EXECUTIVE SUMMARY

LADWP defines power system reliability as the ability to satisfy the present and future electricity demand of its electric utility customers on a continuous basis. To accomplish this, LADWP maximizes control over the generation, transmission, and distribution of electricity for its customers. By building, reinforcing, owning, operating and maintaining a largely self-sufficient power system, LADWP is able to ensure, to the fullest extent possible, that customer demand for electricity is reliably met. Attention to the planning and operations of the power system is necessary to achieve this end as is the procurement of sufficient resources. Success in this regard is measured objectively by the extent LADWP conforms to the reliability standards issued by the North American Electric Reliability Corporation (NERC); the Western Electricity Coordinating Council (WECC), in its capacity as Regional Reliability Organization for NERC's western region, has deemed LADWP reliable based on its audits, the last conducted in January 2011.

A key factor to maintaining power system reliability is LADWP's ability to continuously provide readily available generation resources during normal operations and for credible outages of transmission and generation resources. Because the Los Angeles Basin (Basin) transmission is insufficient to fully meet customer demand from imported energy, such generation must be located in the Basin to ensure system security. The City has four thermal Basin plants which are suitable for such purposes: Haynes, Harbor, Scattergood, and Valley Generating Stations. All but Valley Generating Station are ocean-water cooled coastal power plants and subject to the State's "Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling" adopted on May 4, 2010 by the SWRCB. To comply with this OTC Policy, referring to the channeling of cool ocean waters through the heat exchanger in a single-pass before being returned to the ocean, LADWP is replacing the OTC units at its three coastal generating plants with closed-cycle cooling systems. The work is scheduled to be completed by December 2029.

The reliability investigations included in this 2012 Report, which are described herein, together with the 2011 Report, consistently show that maintaining its Basin generation capacity is critical to maintaining LADWP's power system reliability. Specifically:

- ☐ The 2012 Ten-Year Transmission Assessment (2012 Assessment) clearly shows key segments of LADWP's transmission system must be reinforced in order to ensure continued reliable operations. Chief among these necessary improvements is the installation of the 230kV Scattergood-Olympic Line 1, which improves the ability to transmit power from Scattergood Generating Station throughout the Basin.

[redacted]

- The "2021 Local Capacity Technical Analysis" report (LCT Report) prepared for the California Environmental Protection Agency's Air Resources Board (CARB) in February 2012 to support their Assembly Bill 1318[1] (AB1318) Project, shows the existing Basin generation resources may not sufficiently ensure undisrupted power service to LADWP customers. Additional generating resources should be obtained.

- The Transmission Reliability Assessment for Summer 2012 shows every Basin plant is needed for reliability purposes. In fact, every plant was ready to compensate for generation lost from a statistically-likely power system disturbance, or contingency.

- The Resource Adequacy Projections show that Basin generation will serve roughly half of the summer's demand.

The studies compiled for this report demonstrate LADWP's longstanding practice of identifying near and long-term reliability concerns so that they are addressed in a timely manner. Only the LCR Study for CARB is a new undertaking. Collectively, these studies indicate LADWP is positioned, with the implementation of the improvements described herein, to reliably service the electricity needs of its customers, even in the event of a reasonably likely electrical disturbance which is expected to occur from time to time.

The results from this 2012 Report suggest that because every Basin plant is needed to ensure a reliable LADWP electric grid, LADWP can provide limited, if any, local capacity assistance to its CaISO neighbor. This outcome was realized when CaISO sought such support from LADWP this summer to overcome the 2200MW lost from the forced shut-down of their San Onofre Nuclear Generating Station (SONGS). If capacity were available, LADWP could only provide general, but not local, capacity relief. The more critical relief for CaISO's southern area served by SONGS from its Northern San Diego County location was unreachable because CaISO's transmission paths were already congested. CaISO's other options to increase local capacity support to its southern area suffered the same transmission constraint. In the end, CaISO returned to service mothballed OTC units at AES Huntington Beach in Orange County.

[1] Electrical System Reliability Needs of the South Coast Air Basin, a.k.a. AB1318, was enacted on October 11, 2009.

[redacted]

2012 Reliability Report

PREPARED FOR CALIFORNIA STATE WATER RESOURCES CONTROL BOARD

RELIABILITY: DEFINITION AND COMPLIANCE

LADWP's first priority is to ensure the reliability of its power system at all times. As such, LADWP fully supports the state policy goals identified in this report, including the OTC Policy, but its first priority is to uphold the City Charter's mandate to provide reliable electric service to its customers.

There are two basic aspects to power system reliability: system adequacy and system security. System adequacy relates to having sufficient facilities in place to service the customer demand for electricity. As a vertically integrated utility[2], LADWP is obligated to have, whether owned or contracted, properly networked supply, transmission, and distribution facilities so that its customers are nominally provided with uninterrupted electric service. System security relates to the necessary robustness of the system so that it can withstand reasonable disturbances as prescribed in NERC's Reliability Standards and reasonably expect to continue to serve its customers with minimal interruption.

Every electric utility must comply with NERC Reliability Standards applicable to them and LADWP is no exception. Of NERC's fifteen compliance categories, LADWP is registered to carry out twelve, and so must comply with the 1400 individual requirements applicable to these functions:

- Balancing Authority
- Transmission Operator
- Transmission Owner
- Transmission Planner
- Transmission Service Provider

[2] Prior to the Electric Utility Restructuring Act (Assembly Bill 1890), enacted September 23, 1996, all California electric utilities were vertically integrated. With the Act, investor-owned utilities (IOUs) which serve the majority of the State, restructured as parent companies with independent subsidiaries performing the competitive power generation and regulated transmission and distribution functions. The Act also created the California Independent System Operator (CaISO) which operates the pooled transmission assets of the IOUs and other CaISO members. Municipal utilities who decide to join CaISO include their transmission assets in the CaISO pool. LADWP has elected to continue with its traditional service model. LADWP is not a CAISO member and remains vertically integrated, owns its generation, transmission, and distribution systems.

[redacted]

- Planning Authority/Coordinator
- Generator Operator
- Generator Owner
- Resource Planner
- Purchasing-Selling Entity
- Load-Serving Entity
- Distribution Provider

The compliance categories that do not apply to LADWP are: Interchange Authority, Reliability Coordinator, and Reserve Sharing Group. WECC serves as both the Interchange Authority and Reliability Coordinator for LADWP. Within WECC are three reserve sharing groups, which are cooperatives comprised of Balancing Authorities to mutually support reliability through pooled resources. As LADWP is relatively self-sufficient, a reserve sharing group would not provide substantial benefits.

Entities registered under any of the fifteen compliance categories must comply with the Reliability Standards associated with their compliance categories. Not surprisingly, because LADWP is registered to carry out twelve compliance categories, it is required to conform to thirteen Reliability Standard categories, able only to omit Nuclear Standards (NUC) from its domain of responsibility:

- Resource and Demand Balancing (BAL)
- Communications (COM)
- Critical Infrastructure Protection (CIP)
- Emergency Preparedness and Operations (EOP)
- Facilities Design, Connections, and Maintenance (FAC)
- Interchange Scheduling and Coordination (INT)
- Interconnection Reliability Operations and Coordination (IRO)
- Modeling, Data, and Analysis (MOD)
- Personnel Performance, Training, and Qualifications (PER)
- Protection and Control (PRC)

[redacted]

- Transmission Operations (TOP)
- Transmission Planning (TPL)
- Voltage and Reactive (VAR)

Along with its counterparts in WECC, one of NERC's eight Regional Entities, LADWP submits to a WECC compliance audit every three years. Since NERC Reliability Standards became enforceable in June 2007, WECC has audited LADWP twice, in April 2008 and in January 2011, concluding on both occasions LADWP's power system is reliable. LADWP intends to maintain this favorable standing and its longstanding reputation as a reliable electric service provider.

WECC's oversight and enforcement of NERC Reliability Standards enhances power system reliability for LADWP and the vast interconnected WECC electricity grid which covers the western United States and Canadian Provinces and northernmost Mexico. Additionally, LADWP actively participates in WECC activities to coordinate and promote inter-regional power system reliability. At the state level, LADWP was actively engaged in the California Transmission Planning Group (CTPG) to ensure the electricity needs and state policy goals are reliably and efficiently met; LADWP chaired the Technical Steering Committee to annually develop the two statewide transmission plans produced.

Compliance with NERC TPL Standards is demonstrated by documenting power system performance meeting specifications in repeatable contingency-based studies. The performance criteria for the four categories described in Table 2 and in Appendix 2 relate to NERC TPL Standards. It must be noted that demonstrated conformance to the more aggressive contingencies in Categories C and D is optional in specific circumstances.

TABLE 2. PERFORMANCE CRITERIA FOR NERC CONTINGENCIES

Contingency Category	**Study**	**Performance Criteria**
A	N-0 Contingency: all facilities in service	All elements within normal thermal and voltage limits
B	N-1 Contingency: loss of 1 element	All elements within emergency thermal and voltage limits after loss
C	N-1-1 Contingency with Special Protection Schemes (SPS) Stabilized, system-adjusted N-1 experiences loss of 1 additional element	All elements within emergency thermal and voltage limits; SPS may be utilized to achieve this desired result
C	N-2 Contingency: loss of 2 elements simultaneously	All elements within emergency thermal and voltage limits; SPS may be utilized to achieve this desired result
D	N-n Contingency: Extreme event resulting in loss of multiple elements	Cascading outages may result

[redacted]

LADWP LOADS AND RESOURCE ADDITIONS

LOAD FORECAST

Table 3 explicitly describes the different applications for using the “City of Los Angeles Department of Water and Power 2011 Retail Electric Sales and Demand Forecast” dated February 18, 2011 (2011 Load Forecast) and the “City of Los Angeles Department of Water and Power 2012 Retail Electric Sales and Demand Forecast” dated March 7, 2012 (2012 Load Forecast). (Appendix 1)

Ideally, the same load forecast would be used for the studies included in each annual grid reliability report. In this filing, however, the 2012 Resource Adequacy Projection, which will be the basis for the 2012 Integrated Resource Plan, is provided in advance of the plan’s release.

TABLE 3. LOAD FORECAST USED FOR EACH STUDY IN 2012 GRID RELABILITY REPORT

Study	2011 Load Forecast	2012 Load Forecast
2011 Ten-Year Transmission Assessment	X	
2021 Local Capacity Technical Analysis	X	
Transmission Reliability Assessment for Summer 2012	X	
Resource Adequacy Projections		X

The one-in-ten year load forecast assumes a heat storm each year such that there is a 90% likelihood that the actual demand will not exceed the forecast.

TABLE 4. TEN-YEAR ONE-IN-TEN NET-ENERGY-FOR-LOAD FORECAST (MW)

	2011 Load Forecast (MW)		2012 Load Forecast (MW)	
Year	**Peak Demand**	**Cogeneration**	**Peak Demand**	**Cogeneration**
2011	6096	224	5907, actual	
2012	6092	239	6046	232
2013	6089	258	6014	238
2014	6188	277	6042	243
2015	6277	293	6028	248
2016	6365	306	6026	252
2017	6442	314	6034	254
2018	6527	319	6099	256
2019	6615	316	6072	258
2020	6710	319	6244	261
2021	6830	330	6342	264
2022	6909	337	6409	267

RENEWABLE GENERATION ENHANCEMENTS

As with its California electric utility counterparts, LADWP is aggressively interconnecting and acquiring renewable resources in order to attain the 33% Renewable Portfolio Standard (RPS) goal by 2020. In 2011, LADWP's Commissioners adopted interim targets to conform to SBX1-2. In 2012, both the 10MW Adelanto Solar Project and the 8.5MW Pine Tree Solar Project were placed in service.

TABLE 5. LARGE-SCALE RENEWABLE RESOURCE ADDITIONS

Project	Type	In-Service	Capacity (MW)	Energy (GWh)
Pine Tree	Solar	Dec2012	8.5	17
Adelanto	Solar	Jun2012	10	22.4

Distributed generation (DG) is expected to play an increasing role, contributing 150MW or more, primarily from solar facilities incented by LADWP's Solar Incentive Program (SIP), an existing program, and Feed-in-Tariff Program (FiT), which is completing its pilot phase and is scheduled to be fully implemented in early 2013.

[redacted]

Statewide Policy for LADWP: *33% of LADWP's retail load is satisfied with renewable energy by 2020, with interim goals of 20% by 2013 and 25% by 2016 (SBX1 2 chaptered on April 12, 2011).*

- LADWP is the largest municipal utility in the state to meet the 20% goal in 2010.

- LADWP's Commission has established renewable portfolio standard targets of 20% minimum through 2013; 25% by 2016; 33% by 2020; 33% minimum thereafter (Commission Resolution 012-109 adopted on December 6, 2011). These targets modify the renewable portfolio standard target of 35% by 2020 (Commission Resolution 008-247 adopted on May 20, 2008).

Statewide Policy for LADWP: LADWP makes an acceptable contribution toward California's Clean Energy Future 2020 goal of 5 gigawatts of installed localized generation capacity (or Governor Brown's 2020 goal of 12 gigawatts). The installed localized generation capacity would include an acceptable contribution toward California's 750 MegaWatt Feed-in-Tariff (FiT) Program (SB32 chaptered on October 11, 2009).

- LADWP is phasing in up to 150MW from FiT by 2016. This represents a 100% increase above the state mandate, defined by SB32 as LADWP's proportionate share of the total statewide peak demand. LADWP is also phasing in up to 187MW from SIP; and 88MW from larger utility-built projects by 2020.

FOSSIL-FUELED GENERATION ENHANCEMENTS

LADWP is modernizing its coastal Harbor, Haynes, and Scattergood Generating Stations so plant operations will continue to be in accordance with all existing regulations. In an effort to reduce the environmental footprint:

- ☐ Coastal Waters will no longer be used to cool the power plants as the units using ocean water cooling intake structures will be replaced with those using closed-cycle cooling systems. The new technology relies on recirculating cooling water and exceeds the required 93% reduction in intake flow rate for each repowered unit.

- ☐ No new capacity will be added at the plants.

- ☐ Increased Production Efficiency will reduce the emission of air-borne by-products on a per MW basis.

- ☐ New plants will better respond to the intermittency of the increased renewables.

[redacted]

TABLE 6. LADWP'S REPOWERING SCHEDULE

Generating Station	Generating Unit	In-Service
Harbor	Unit 5	31 Dec 2029
Haynes	Unit 1	31 Dec 2029
	Unit 2	31 Dec 2029
	Unit 5	31 Dec 2013
	Unit 6	31 Dec 2013
	Unit 8	31 Dec 2029
Scattergood	Unit 1	31 Dec 2024
	Unit 2	31 Dec 2024
	Unit 3	31 Dec 2015

Statewide Policy for LADWP: *Greenhouse gas emissions from LADWP's power plants are reduced to 1990 levels by 2020 to assist the State of California in reducing overall statewide emissions (AB32 chaptered on September 27, 2006).*

Statewide Policy for LADWP: *The California Energy Commission has established the 1100lb CO_2 per megawatt-hour emissions standard for any new investments in utility-owned base-load generating plants or long-term power purchase agreements for base-load generation (SB1368, chaptered on September 29, 2006).*

- Approximately 40% of LADWP's retail energy is generated from two coal-fired generating stations: Utah's Intermountain Generating Station (IGS) and Arizona's Navajo Generating Station (NGS). Although its coal-fired plants provide reliable low-cost energy, LADWP is giving serious consideration to the early divestiture of these assets (Sections 3 and 4 of the 2011 Integrated Resource Plan).

- LADWP's repowering plans for its coastal plants will replace existing generating units with more efficient, combined-cycle and fast-response simple-cycle turbines to reduce greenhouse emissions while flexibly supporting deliveries of intermittent energy.

TRANSMISSION ENHANCEMENTS

Because LADWP serves a metropolis, system reinforcements, additions, and improvements within City boundaries are often challenging with extended construction in crowded thoroughfares where right-of-ways may be lacking and the required removal

[redacted]

from service of critical transmission segments to complete the project. Compounding this challenge is the very real need to invest in an aging transmission infrastructure that has been providing reliable electric service since 1916. LADWP has explored and exercised economically and operationally feasible options to increase the ratings and flexibility of its resources and continues to do so, including dynamically rating critical Basin belt-line segments. LADWP is investing in Basin capital projects to the extent feasible. Northridge-Tarzana Line 1, reconductored in June 2012, is one example on such investment.

Beyond the Basin, LADWP is pursuing plans for providing the additional capacity necessary to transmit energy from renewable resources north of Los Angeles. Such activity comes on the heels of a 480MW upgrade in January 2011 of the Intermountain Power Project HVDC line (IPPDC), a.k.a. Southern Transmission System (STS), to increase the capacity to transmit renewable energy from Utah for LADWP and its Southern California Public Power Authority (SCPPA) partners.

TABLE 7. [redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Statewide Policy for LADWP: *LADWP is interconnecting to its transmission system renewable projects to satisfy the renewable portfolio standard.*

- LADWP Open Access Same-time Information System (OASIS) lists 31 renewable resource projects with a total capacity of over 4500MW in its Generator Interconnection Queue as of August 22, 2012. All have in-service dates prior to 2020.

- LADWP's renewable portfolio standard target of 20% by 2010 was achieved on time (Commission Resolution 007-197 adopted on April 17, 2007).

[redacted]

BACKGROUND

Annually, LADWP engages in a comprehensive Ten-Year Transmission Assessment, a.k.a the Ten-Year Plan, to identify vulnerabilities in the transmission system. As a summer-peaking system, LADWP aggressively studies the impact of disturbances on expected one-in-ten heavy summer peak demands with all power system elements operating. This is reasonable as maintenance and other planned outages would not be scheduled when facilities are most needed. Light winter conditions for a sampling of years are also studied to identify any voltage issues due to light system loading. The studies ensure LADWP conforms to NERC Reliability Standards TPL-001, TPL-002, TPL-003, TPL-004. The Ten-Year Plan is attached to this report as Appendix 3.

[redacted]

- [redacted]

- [redacted]

- [redacted]

- [redacted]

CONTINGENCIES STUDIED

Table 8 summarizes the load flow studies performed in the 10-Year Plan. Transient and post-transient stability and reactive margin studies are performed on any disturbances resulting in constrained power flows.

[redacted]

TABLE 8. SUMMARY OF CONTINGENCIES STUDIED IN 2011 TRANSMISSION ASSESSMENT

Study Parameter	Heavy Summer	Light Winter
Study Years	2012-2021	2012 and 2016
Power Flows	Heavy loads throughout WECC	Exports to Pacific NW
NERC Category A (N-0)	Yes	Yes
NERC Category B (N-1). Generator	Non-issue	Non-issue
Transmission Line	All	All
Transformer	All	All
Single Pole (DC)	Non-issue	Non-issue
NERC Category C. Bus Section	Non-issue	Non-issue
Breaker Failure	Non-issue	Non-issue
Stabilized, System-adjusted N-1 suffers N-1	--	--
Bipole (DC)	All	All
2 Circuits on multi-circuit tower line	All	All
Stuck Breaker/SPS Failure	Non-issue	Non-issue
NERC Category D Stuck Breaker/SPS Failure	Optional	Optional
Breaker Failure	Optional	Optional
Towerline with 3 or more circuits	Study Year 2016	Study Year 2016
Transmission Lines on common Right-of-Way	Study Year 2016	Study Year 2016
Substation Loss	Study Year 2016	Study Year 2016
Other multiple contingencies	Optional	Optional

2021 LOCAL CAPACITY REQUIREMENT (LCR)

BACKGROUND

As the City continues to strive toward the state-mandated RPS goal of 33% by 2020, renewable resources will increasingly displace LADWP's fossil-fueled resources. This prioritization requires Basin generating plants to be re-dispatched to fill the base load requirement previously served by out-of-state base-load fossil fuel and fill production gaps created due to the intermittency of these new resources. Local generating capacity, which fills that production void, becomes increasingly important as contributions from these renewable resources continue to increase. Operating LADWP's local coastal Harbor, Haynes, and Scattergood Generating Stations is an issue,

[redacted]

however, because some units at these plants currently rely on ocean water cooling systems.

LADWP is committed to complying with public policies and regulations without sacrificing power system reliability. As the studies in this report show, LADWP relies on each Basin generating asset, including its OTC plants, to maintain the energy supply-demand balance. For that reason, the need to repower and modernize its coastal plants to comply with the State's OTC Policy and air quality regulations rather than retiring the affected units is obvious. The repowering and modernization program, which concludes in approximately sixteen years, ensures the continued reliability of its electric power grid.

As required by AB1318, CARB is studying LADWP's Basin generation requirement in order to allocate emission offsets for new generation within the South Coast Air Quality Management District. To support this AB1318 Project, LADWP's planning engineers have been working since 2011 with Michael Jaske of the California Energy Commission (CEC), David Le of CaISO, and Stephanie Kato and Tung Le of CARB to provide to CARB information needed for the agency to determine LADWP's minimum Basin generation needs and emissions requirements in 2021. The assumptions used in the study were jointly developed by the team. The methodology used is described wholly in CaISO's "2013-2015 Local Capacity Technical Analysis: Final Report and Study Results" report dated December 30, 2010.

The 2011 Report included preliminary results from the high-load scenario which is based on the forecasted one-in-ten load and power system configuration where only LADWP's existing programs in energy conservation, demand-side management (DSM), demand response (DR) and distributed generation (DG) are included. In this Report, the high-load scenario is re-introduced and compared with a mid-load scenario that is based on the stated programs aggressively offsetting the load by 626MW during a one-in-ten summer heat storm.

The local capacity requirements identified and provided in Table 10 were submitted by LADWP to CARB in February 2012. CARB is preparing to report to the Governor and Legislature the emission requirements for the South Coast Air Basin (SCAB) so that generators critical to ensuring power system reliability within SCAB are provided the emissions credits necessary to continue their reliability function.

LOCAL CAPACITY REQUIREMENT (LCR) METHODOLOGY

As the operator for 80% of California's power grid, CaISO's use of LCR as a metric for resource adequacy within its Balancing Authority carries considerable weight. CaISO defines LCR as the minimum capacity within a given geographical area that is necessary to maintain reliable grid operations should certain large contingencies occur. This minimum capacity is determined from a planner's perspective with all resources initially available.

Historically, CaISO's LCR studies were near-term studies projecting no further than five years. CARB, CaISO and LADWP are determining the LCR for 2021.

TABLE 9. LCR STUDY CONDITIONS

Study Parameter	Pre-Contingency Assumptions
Import Capability	Maximized imports Load pocket generation minimized
Path Flows	Maintained within capacity limits
Components and Facilities	Available
Contracted Must-Take Energy	On-line and available
Nuclear Energy	On-line and available

The LCR is determined by fully investigating the Category A and B contingencies described in the TPL Standards. Category C and D contingencies are also investigated but for the following:

1. Category C: loss of a bus section; loss of a breaker due to a failure or internal fault; and a single line-to-ground fault of any kind due to a stuck breaker or system protection failure.

2. Category D: an extreme event with loss of multiple elements beyond a stabilized, system-adjusted N-1 contingency followed by a credible common mode L-2 contingency, which is a simultaneous double-transmission line outage

LOCAL CAPACITY NEEDS IN 2021

TABLE 10. MINIMUM GENERATION FOR 2021 SATISFYING ALL SCENARIOS

Basin Thermal Generation	Capacity	Category B	Category C
Haynes	1619 MW	1440 MW	1600 MW
Harbor	466 MW	227 MW	466 MW
Scattergood	810 MW	600 MW	810 MW
Valley	576 MW	510 MW	510 MW
Total	**3471 MW**	**2777 MW**	**3386 MW**
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

TABLE 11. RELIABILITY MUST-RUN UNITS FOR 2021 SATISFYING ALL SCENARIOS

Basin Thermal Generation	Capacity	Category B	Category C
Haynes	1619 MW	All Units	All Units
Harbor	466 MW	Units 1, 2, and 5	All Units
Scattergood	810 MW	All but Unit 1 or 2	All Units
Valley	576 MW	All but Unit 5	All Units

TABLE 12. MINIMUM GENERATION FOR 2021 HIGH-LOAD SCENARIO @ MAX PDCI

Basin Thermal Generation	Capacity	Category B	Category C
Haynes	1619 MW	1440 MW	1600 MW
Harbor	466 MW	227 MW	466 MW
Scattergood	810 MW	600 MW	810 MW
Valley	576 MW	510 MW	510 MW
Total	**3471 MW**	**2777 MW**	**3386 MW**
[redacted]	[redacted]	[redacted]	[redacted]

TABLE 13. MINIMUM GENERATION FOR 2021 MID-LOAD SCENARIO @ MAX PDCI

Basin Thermal Generation	Capacity	Category B	Category C
Haynes	1619 MW	1440 MW	1600 MW
Harbor	466 MW	227 MW	466 MW
Scattergood	810 MW	600 MW	810 MW
Valley	576 MW	510 MW	510 MW
Total	**3471 MW**	**2777 MW**	**3386 MW**
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

TABLE 14. MINIMUM GENERATION FOR 2021 HIGH-LOAD SCENARIO @ MIN PDCI

Basin Thermal Generation	Capacity	Category B	Category C
Haynes	1619 MW	740 MW	1600 MW
Harbor	466 MW	227 MW	466 MW
Scattergood	810 MW	600 MW	810 MW
Valley	576 MW	510 MW	510 MW
Total	**3471 MW**	**2077 MW**	**3386 MW**
[redacted]	[redacted]	[redacted]	[redacted]

DISCUSSION OF FINDINGS

The minimum generation requirements for both the high-load and mid-load scenarios emphasize the need for additional generation in the Basin than is expected to be present in 2021 regardless of whether CARB elects to establish the minimum generation requirement using Category B or Category C. With Category B, load must be shed to return transmission lines operating at or near emergency ratings to their normal rating before the permissible two-hour time limit. This controlled load-shedding disrupts electric service for a limited number of customers but maintains overall power system reliability. In order to withstand the more challenging Category C contingencies, as much as 358MW must be shed for transmission lines to operate within emergency ratings; additional load-shedding would then reduce line loads to within their normal ratings. In short, restoration of LADWP's power system following the conditions studied would require load to be shed.

The results from this LCR study suggest the City can ill-afford to have any of its Basin generating units unavailable in 2021. For this reason, the negotiated compliance schedule for repowering, which does not retire any of its OTC generating units without having an equivalently-sized, locationally-equivalent replacement ready to be placed in-service, is necessary.

Those familiar with LADWP may point to the City's hydroelectric power plants in or near the Basin as resources that can be dispatched for power system reliability: Castaic Power Plant, and a number of smaller facilities. Indeed, the City's 1250MW pump storage facility at Castaic supports the intermittent renewable resources interconnecting along the Owens Valley Transmission Corridor, effectively firming and shaping the energy entering the Basin from the Owens Valley. However, Castaic is 22 miles from the northernmost City limits. As such, it is not useful as a Local Capacity Requirement resource dispatched to counteract disturbances on the basin transmission system.

[redacted]

BACKGROUND

LADWP's operating engineers rigorously determine LADWP's minimum generation requirement for multiple load levels daily. Near-term seasonal assessments are also regularly performed to ensure maintenance and other scheduled outages can proceed without detriment to the power system. The Summer 2012 Transmission Reliability Assessment, currently LADWP's most recent high-load seasonal assessment, provides the minimum generation requirement, referred to in-house as the Reliability Must-Run (RMR) requirement.

RMR is defined as that generation that is either synchronized or available within two hours such that the following criteria are met:

1. All circuit loadings shall be less than the circuits' continuous ratings, and all voltages shall be normal.

2. Following the worst single generation or transmission contingency, the loading on the most severely stressed transmission circuit shall be less than that circuit's 2-hour rating, and the voltage on the transmission side of all load banks shall be at or above 95% of nominal voltage.

3. Assuming the worst single contingency is not restored within 2 hours, sufficient LADWP generation shall be available within 2 hours to relieve loading on all circuits to the circuits' continuous ratings, and restore voltage to 100% of normal.

To determine the RMR, operating engineers hone in on two scenarios: one snapshot supposes maximum imports from the Victorville-to-Basin system with the Pacific DC Intertie (PDCI) minimally scheduled; the other maximizes PDCI imports with high output from Castaic. In each scenario, Basin cogeneration is deemed off so the summer peak for the study is 6331MW which is the forecasted peak demand in 2012, from the 2011 Forecast, with 239MW of anticipated cogeneration switched off. The 2011 Forecast had offset the predicted load with the predicted contribution from Basin cogeneration.

The intra-Department memorandum related to this study is provided in Appendix 3.

SECURITY NEEDS

TABLE 15. RELIABILITY MUST-RUN UNITS IN SUMMER 2011

Basin Thermal Generation	LADWP's RMR for Summer 2011
Harbor	Units 1 and 2 and 10-14 @ full load within 2hours
Haynes	Units 1, 5, 6, 8, 9, and 10
Scattergood	Units 1 or 2, and 3
Valley	Units 6, 7, and 8

TABLE 16. 2-HOUR SECURITY NEEDS IN SUMMER 2012

Basin Thermal Generation	Capacity	Minimum PDCI	Maximum PDCI
Harbor	466 MW	--	--
Haynes	1619 MW	698 MW	534 MW
Scattergood	810 MW	472 MW	554 MW
Valley	576 MW	326 MW	280 MW
Total	**3471 MW**	**1496 MW**	**1368 MW**

TABLE 17. CONTINUOUS SECURITY NEEDS IN SUMMER 2012

Basin Thermal Generation	Capacity	Minimum PDCI	Maximum PDCI
Harbor	466 MW	397 MW	397 MW
Haynes	1619 MW	1061 MW	1242 MW
Scattergood	810 MW	604 MW	604 MW
Valley	576 MW	307 MW	306 MW
Total	**3471 MW**	**2369 MW**	**2549 MW**

The significant difference between the previous year's Summer Transmission Reliability Assessment and this year's is that LADWP now assumes Units 1 and 2 at the City of Burbank's Olive Power Plant are off and unavailable, as recommended by management at Burbank's Control Center. Absent the 100MW from these Olive units, RMR generation has been increased at Haynes.

[redacted]

MINIMUM LOCAL CAPACITY REQUIREMENT FOR SUMMER 2012

The Summer 2012 Transmission Reliability Assessment includes information which suggests a minimum Summer 2012 LCR. This information, summarized in Table 18, was developed from investigating critical contingencies. The critical contingencies identified are generally described as the loss of a Basin generating unit followed more than 30 minutes later by the loss of a transmission line, so that a new system equilibrium is established in between. Such contingencies are classified as NERC Category C contingencies. As Table 18 shows, there are severe consequences to the critical contingencies occurring even when neighboring Basin generation has been dispatched at maximum rated output. Table 19 develops what can only be considered the minimum LCR for Summer 2012. This is because the Summer 2012 Transmission Reliability Assessment is an operations report with an operations focus while the LCR is a planning issue.

TABLE 18. (GENERATOR-1) FOLLOWED BY (LINE-1) RESULTS FOR SUMMER 2012

1st Contingency	2nd Contingency	Generation @ Pmax	Load Shed
Haynes CC Unit	Adelanto-Toluca 1	Haynes 1,2,5,6,7 Harbor 1,2,5,10,11,12,13,14	145 MW
Valley CC Unit	Valley-Rinaldi 1 or 2	Haynes 1,2,5,6,7,8,9,10 Harbor 1,2,5,10,11,12,13,14 Valley 5	149 MW
Scattergood 3	Rinaldi-Tarzana 1 or 2	Scattergood 1 and 2	56 MW

TABLE 19. MINIMUM LCR FOR SUMMER 2012

Basin Thermal Generation	Capacity	Category B	Category C
Haynes	1619 MW	1242 MW	1619 MW
Harbor	466 MW	397 MW	466 MW
Scattergood	810 MW	604 MW	604 MW
Valley	576 MW	307 MW	307 MW
Total	**3471 MW**	**2550 MW**	**2996 MW**
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

BACKGROUND

LADWP annually publishes an Integrated Resource Plan (IRP) Update that includes a multi-year resource adequacy projection that factors in the availability of fossil and renewable resources either owned or contracted through power purchase agreements. Although renewable resources such as wind and solar are intermittent and not subject to dispatch, the IRP does not discount them completely. Rather, the full capacity of these resources is derated to a dependable capacity value: wind is discounted to 10% of nameplate capacity and solar 27%. This differs from the dependable output of distributed generation which is assumed to be the annual average generating capacity for each particular year. Scheduled maintenance and other planned outages are also given consideration in developing the projection. For example, if a generating unit is scheduled to be unavailable for three consecutive days in any month, the unit is not considered available for the entire month in the analysis.

Finally, LADWP maintains an operating reserve margin as required by NERC Standard BAL-STD-002. Accordingly, LADWP's minimum operating reserve equals the sum of:

1. contingency reserves to satisfy NERC Standard BAL-002 such that the loss of generating capacity from the single-most severe contingency can be overcome;

2. replacement reserves to replace the contingency reserve that has been called

3. regulating reserves, with Automatic Generation Control (AGC) to satisfy NERC Standard BAL-001 which ensure steady-state frequencies by balancing demand and supply in real time; and

4. additional reserves to meet on-demand obligations to other entities or Balancing Authorities

The contingency reserve requirement is typically 575MW, equal to the output of the combined-cycle unit at Haynes Station plus 25MW for regulating reserves. The replacement reserve is seasonally adjusted according to the forecast peak load. Together, the contingency reserve requirement and replacement reserve make up the reserve margin which fluctuates seasonally due to the fluctuating replacement reserve.

Both Tables 20 and 21 show an EE/Solar Rooftop Adjustment to LADWP's load forecast. This adjustment accounts for the treatment of electricity from EE/Solar Rooftops as resources by LADWP's resource planners instead of as an offset to the load by LADWP's load forecaster. The adjustment recognizes this difference, avoids any double accounting, and clearly identifies the forecasted contribution from EE/Solar Rooftops.

[redacted]

Term purchases are discretionary transactions that may be necessary to meet load demands. As Table 21 shows, a term purchase of 175MW will cover a June heat storm in 2013. By projecting resources, ECC is able to better manage the balance of supply and demand for electricity and maintain real-time system reliability.

TABLE 20. TEN-YEAR RESOURCE ADEQUACY PROJECTION (MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Large Hydro	1657	1682	1682	1682	1682	1682	1682	1682	1682	1682
Nuclear	383	383	383	383	383	383	383	383	383	383
In-Basin Thermal	3179	3179	3179	3267	3267	3267	3267	3267	3303	3303
Existing Renewables	353	349	333	327	291	291	291	291	291	283
IPP Coal	1191	1191	1191	1191	1191	1191	1191	1191	1191	1141
Navajo Coal	451	451	451	0	0	0	0	0	0	0
Navajo Coal Replacement	0	0	0	300	300	300	300	300	300	300
New Renewables	36	87	223	286	347	393	440	540	547	600
Demand Response	10	20	40	75	100	150	200	250	300	350
Energy Efficiency	37	58	79	99	116	131	144	155	166	175
Term Purchases	175	0	0	0	0	0	0	0	0	0
Others	16	16	16	16	16	16	16	16	16	16
Total Resources	**7488**	**7416**	**7577**	**7626**	**7693**	**7804**	**7914**	**8075**	**8179**	**8233**
EE/SolarRooftop Adjustment[3]	180	247	317	386	449	463	468	472	474	478
Reserve Margin	1,090	1,090	1,090	1,090	1,090	1,090	1,090	1,090	1,090	1,090
1-in-2 Peak	5577	5604	5591	5590	5597	5658	5725	5791	5881	5942
Adjusted 1-in-2	5757	5851	5908	5976	6046	6121	6193	6263	6355	6420
Resource Margin	**641**	**475**	**579**	**560**	**557**	**593**	**631**	**722**	**734**	**723**
Adjusted 1-in-5	6045	6143	6203	6274	6348	6427	6502	6576	6672	6741
Resource Margin	**353**	**183**	**284**	**262**	**255**	**287**	**322**	**409**	**417**	**402**
Adjusted 1-in-10	6218	6319	6380	6454	6529	6610	6688	6764	6863	6933
Resource Margin	**180**	**7**	**107**	**82**	**74**	**104**	**136**	**221**	**226**	**210**

[3] LADWP's Resource Planners consider contributions from energy efficiencies and the production from solar rooftops energy resources. Energy Efficiency is declared as a line item in the table; Solar Rooftop production is declared in the line items for New Renewables and Existing Renewables, as appropriate.

[redacted]

TABLE 21. 2013 RESOURCE ADEQUACY PROJECTION (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Large Hydro	1392	1392	1267	1472	1567	1202	1657	1657	1422	1487	1487	1147
Nuclear	383	383	383	256	383	383	383	383	383	256	383	383
In-Basin Thermal	1763	2058	2239	2191	2264	2692	2692	3179	3179	2793	2105	2145
Existing Renewables	317	317	353	353	353	353	353	353	353	317	317	317
IPP Coal	1180	1180	590	595	1191	1191	1191	1191	1191	1180	1180	1180
Navajo Coal	451	302	302	451	451	451	451	451	451	451	451	451
New Renewables	36	36	36	36	36	36	36	36	36	36	36	36
Demand Response	5	5	5	5	5	5	10	10	10	10	10	10
Energy Efficiency	37	37	37	37	37	37	37	37	37	37	37	37
Term Purchases	0	0	0	0	0	0	175	175	175	175	0	0
Others	2	15	-10	31	25	27	9	16	21	35	35	16
Total Resources	**5566**	**5725**	**5202**	**5427**	**6312**	**6377**	**6994**	**7488**	**7258**	**6777**	**6041**	**5722**
EE/SolarRooftop Adjustment[4]	76	76	135	157	122	143	185	180	192	176	79	78
Reserve Margin	725	775	775	775	775	1,090	1,090	1,090	1,090	1,090	775	775
1-in-2 Peak	3823	3797	3796	4111	4431	4692	5266	5577	5278	4499	3958	3928
Adjusted 1-in-2	3899	3873	3931	4268	4553	4835	5451	5757	5470	4675	4037	4006
Resource Margin	**942**	**1,077**	**496**	**384**	**984**	**452**	**453**	**641**	**698**	**1,012**	**1,229**	**941**
Adjusted 1-in-5	4094	4067	4128	4481	4781	5077	5724	6045	5744	4909	4239	4206
Resource Margin	**747**	**883**	**299**	**171**	**756**	**210**	**180**	**353**	**425**	**778**	**1,027**	**741**
Adjusted 1-in-10	4211	4183	4245	4609	4917	5222	5887	6218	5908	5049	4360	4326
Resource Margin	**630**	**767**	**182**	**43**	**620**	**65**	**17**	**180**	**260**	**638**	**906**	**621**

[4] LADWP's Resource Planners consider contributions from energy efficiencies and the production from solar rooftops energy resources. Energy Efficiency is declared as a line item in the table; Solar Rooftop production is declared in the line items for New Renewables and Existing Renewables, as appropriate.

[redacted]

Statewide Policy for LADWP: *LADWP meets annual energy efficiency targets established under AB2021 (chaptered on September 29, 2006)in collaboration with the California Energy Commission such that the statewide goal of 13.2 to 18 terawatt-hours in reductions are met by 2020 (California's Clean Energy Future dated September 21, 2010).*

- The dependable contribution from energy efficiency programs is expected to grow from less than 20MW in 2012 to 155MW by 2020, a nine-fold increase.

Statewide Policy for LADWP: *LADWP implements a high-priority demand response program that, where feasible, relieves transmission thermal overloads and/or system stability consequences of credible contingencies.*

- The contribution from demand response programs is expected to grow from 5MW in 2012 to 250MW by 2020.

DISCUSSION

The Ten-Year Resource Adequacy Projection reflects the resource profile in August for each of the next ten years. That is when, along with the rest of Southern California, LADWP's annual peak historically occurs. Any resource shortfall that month is most severe as LADWP would compete with its neighboring counterparts for scarce resources. Indeed, scheduled maintenance and equipment outages occur in the off-peak months so all equipment will be ready and available during the summer. Any resource deficiencies during the off-peak seasons can be resolved with readily available market purchases.

Overall, the projections suggest LADWP should have sufficient resources over the next decade if the assumptions are valid, including those pertaining to Basin generation. As the 2021 Local Capacity Requirement study discussed earlier shows, every Basin unit is required to satisfy the dual responsibilities of meeting peak demand and maintaining system security.

[redacted]

APPENDIX 1. 2011 AND 2012 LADWP LOAD FORECASTS

[redacted]

This page is intentionally left blank

CITY OF LOS ANGELES

DEPARTMENT

OF

WATER AND POWER

2011 RETAIL ELECTRIC SALES AND DEMAND FORECAST

Aram Benyamin
Senior Assistant General Manager
Power System

Ann M. Santilli
Interim Chief Financial Officer

February 18, 2011
Load Forecasting, Room 956
Financial Services Organization

Table of Contents

2011 Retail Electric Sales and Demand Forecast

Overview

The 2011 Forecast (Forecast) supersedes the April 2010 Retail Electric Sales and Demand Forecast as the City of Los Angeles Department of Water and Power's (LADWP) official Power System Forecast. The Forecast is the basis for LADWP Power System planning activities including but not limited to Financial Planning, Integrated Resource Planning (IRP), Transmission and Distribution Planning and Wholesale Marketing.

Because the Forecast is a public document, only publically available information is used in its development. (This practice has become a standard among California electric utilities.) LADWP Planners wishing to use their own proprietary data should adjust the Forecast accordingly. The Load Forecast Group (LFG) is available to help Planners make adjustments and produces an Unmitigated and Gross Forecast to facilitate those adjustments.

Data Sources

1. Historical Sales reconciled to the Consumption and Earnings Report prepared by General Accounting.
2. Historical NEL, Peak Demand and Losses reconciled to the Powermaster database located at the Energy Control center.
3. Historical weather data is provided by the National Weather Service and Los Angeles Pierce College.
4. Historical Los Angeles County employment data is provided by the State of California Economic Development Division using the March 2009 Benchmark.
5. Historical population estimates and projections are provided by the State of California Department of Finance.
6. The long-term Los Angeles County economic forecast with quarterly short-run updates is provided by UCLA Anderson Forecast.
7. The construction activity forecast is provided by McGraw-Hill Construction.
8. The plug-in hybrid electric vehicle (PHEV) forecast is based on the California Energy Commission (CEC) statewide PHEV forecast.
9. The port electrification forecast is provided by the Port of Los Angeles.
10. The housing forecast is informed by the City of Los Angeles "Housing that Works" plan.
11. The energy efficiency forecast is based on approved LADWP-based programs through fiscal year 2013 and the forecasted impacts of the Energy Independence Security Act (EISA) and the Huffman Bill on residential lighting. Historical installation rates are provided by the Energy Efficiency group.
12. Historical solar rooftop installations and objectives are provided by the Solar Energy Development group.
13. Electric Price Forecast is developed by Financial Services organization.

Historical data is current through December 2010.

Five-Year Sales Forecast

The Retail Sales Forecast represents sales that will be realized at the meter through Fiscal Year End 2013. After FYE 2013, some of the forecasted sales will not be realized at the meter due to the incremental impacts of LADWP-sponsored energy efficiency programs. Available in-house is a Gross Forecast which forecasts sales before the impacts of energy efficiency and solar rooftop. The purpose of the Gross Forecast is to allow modeling of different energy efficiency and distributed generation scenarios.

The historical accumulated Energy Efficiency and Solar Saving are from 1999 forward and only include LADWP installed savings. Since July 1, 2006, LADWP-installed Energy Efficiency savings are 715 GWH for which LADWP recovers lost revenue. In the Forecast, energy efficiency and solar savings are expected to occur uniformly throughout the year as a simplifying assumption. Installation schedules are difficult to prepare because they rely on the customers allowing the installation to occur.

Retail sales decrease of 1.4 percent in Fiscal Year 2010-11 is partially attributed to a cooler than normal summer which has already occurred. Likewise, the 0.7 percent increase in Fiscal Year 2011-12 includes the cooler summer in 2010 compared against normal summer weather.

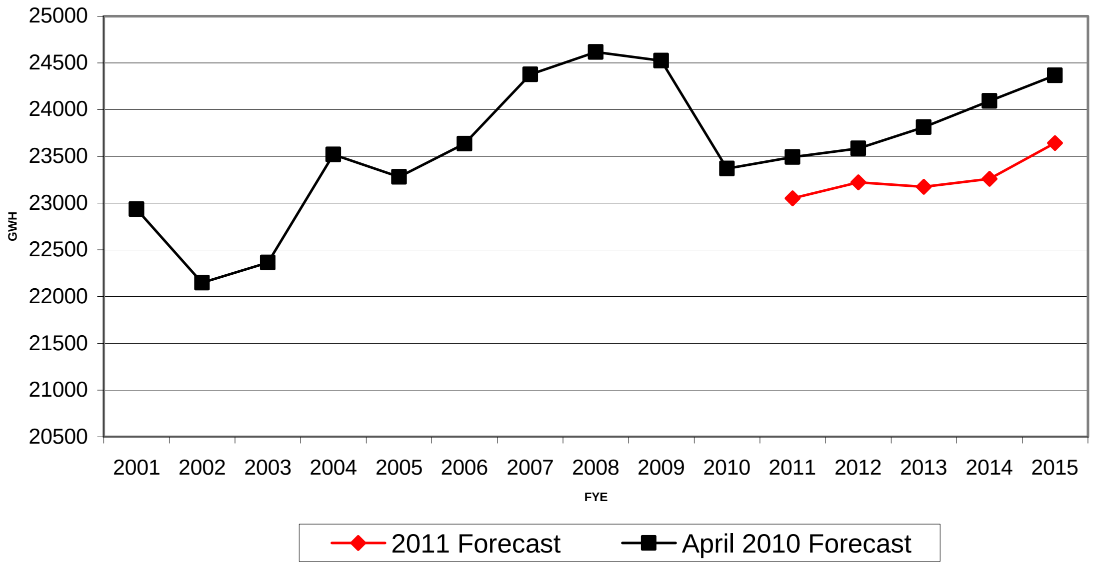
Forecasted Energy Efficiency is based on the California Energy commission definition of "committed " energy efficiency which is LADWP budget through FYE 2013 and forecasted Huffman bill savings. The long-run LADWP energy efficiency goal is to reach the AB 2021 objective of 10 percent savings during the time period 2007 through 2016. The targeted goal for rooftop solar installations is 148 MW by 2020.

Short-Run Growth

Fiscal Year	Retail Sales		Accumulated EE & Solar Savings	Gross Sales
Ending June 30	(GWH)	YOY Growth Rate	(GWH)	(GWH)
2009-10	23369		1289	24658
Forecast				
2010-11	23051	-1.4%	1465	24516
2011-12	23221	0.7%	1672	24893
2012-13	23175	-0.2%	1965	25140
2013-14	23258	0.4%	2217	25475
2014-15	23641	1.6%	2334	25975

[1] Actual sales through December 2010

Retail Sales Net of Energy Efficiency and Distributed Generation



Peak Demand Forecast

Growth in annual peak demand over the next ten years is 0.8 percent.

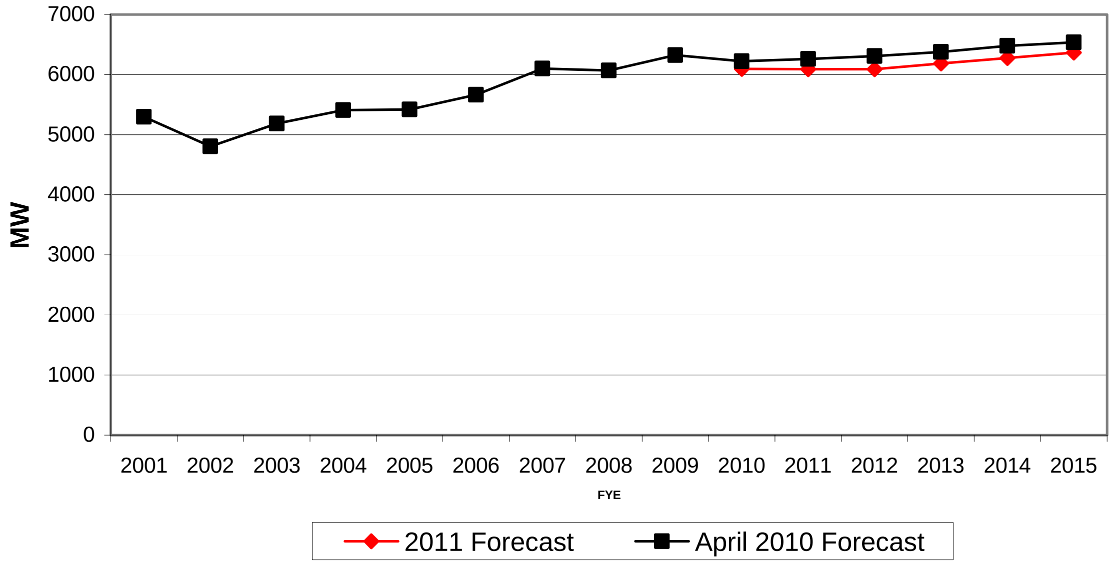
Long-Run Growth

Fiscal Year End June 30	**Base Case Peak Demand (MW)**	**Growth Rate Base Year 2010-11**	**One-in-Ten Peak Demand (MW)**
2010-11	5589[1]		6042
Forecast			
2015-16	5809	0.8%	6277
2020-21	6211	1.0%	6710
2030-31	7000	1.1%	7560
2040-41	7780	1.1%	8403

[1]Weather-normalized. Actual peak was 6142 MW.

In 2010, the System set its calendar annual peak at 6142 MW on September 27, 2010 on a day that was a one-in-thirty-seven weather event. The weather-adjusted one-in-two peak for 2010 is 5589 MW. The following graph of the One-in-Ten peak demand forecast is used for the Integrated Resource Plan (IRP). In the 1990s through 2005, annual System load factors were trending slowly upward. Since 2006, System load factors are trending down. Two factors are generally thought to be contributing to this effect. Most customers are making greater efforts to conserve energy but during extreme weather events safety and comfort predominate over conservation causing the peak to spike. Much of the historical and forecasted energy efficiency effort is lighting which has a greater impact on consumption rather than peak which lowers the load factor.

One-in-Ten Peak Demand Comparisons



The Peak Demand Forecast is primarily used in the following areas:

1. Integrated Resource Planning
2. Wholesale Energy Marketing
3. Distribution Planning
4. Transmission Planning

In Integrated Resource Planning, LADWP uses the One-in-Ten Case Peak Demand forecast rather than the Base Case forecast. LADWP's policy is to ensure reliability in times of volatility by controlling its own generation capacity. Planning generation resources at the one-in-ten level has proven over the years to be an effective tool in meeting the reliability policy. The one-in-ten case is based on historical peak day weather events and uses a statistical model and the underlying retail sales forecast to forecast an annual peak demand.

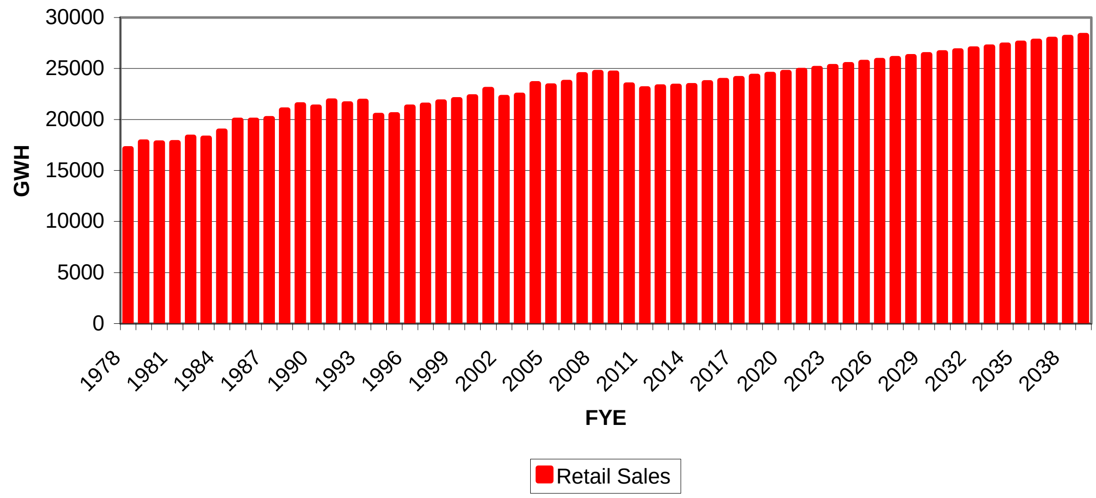
Plausibility

To measure plausibility we compare the current forecast to historical periods. Data is available electronically from 1978 forward. A direct comparison is not appropriate because the forecast period includes programs that reduce all forms of energy consumption due to an aggressive regulatory agenda primary aimed at reducing greenhouse emissions. Instead the unmitigated forecast is compared against history. The unmitigated forecast is the forecast that would occur before the impacts of AB 32 and AB 2021 are considered. It might also be considered a "business-as-usual" case.

The decline in forecasted sales 2008 through 2010 is most directly compared to the decline in sales between 1992 and 1994. The 1992 through 1994 time period was difficult for Los Angeles in many aspects. An economic slump occurred mostly created by the downsizing of the aerospace industry but it also was time of civil unrest and natural disaster. The combination of events caused a major migration of people leaving Los Angeles. Peak-to-Trough sales declined 7 percent in the 1992 through 1994 time period. The following table shows all the peak-to-through declines since 1978. The chart then gives visual evidence of the long-term perspective.

Peak-to-Trough Analysis		
Years	GWH Decline	Percent Decline
2008-2010	1,910	8.3%
1992-1994	1,421	7.0%
2000-2002	572	2.6%
1979-1980	322	1.8%
1981-1982	145	0.8%

Retail Sales before Regulatory Impacts



Primarily due to the recession that began in December 2007 and ended in June 2009, the historical sales experienced a decline of 8.3 percent in the 2008 through 2010 time period. While the 1992-94 sales decline was specific to Los Angeles and the aerospace industry, in 2008-2010 the decline in Los Angeles mirrored the malaise in the national economy. Most economic models based on history would have predicted a faster economic recovery given the amount of publicly-announced fiscal and monetary stimulus. The actual fiscal stimulus was below the announced target. According to www.recovery.gov , only 40% of the funds made available by Recovery Act have been spent as September 2010. Monetary policy has worked for large firms that can reach international markets as the S&P 500 in 2010 neared historical peak earnings. S&P 500 companies have created over one million jobs in the USA according to Economy Policy

Institute. Small firms continue to struggle as loan requirements are stringent and there is a reluctance to invest given the economic uncertainty. UCLA Anderson is forecasting the Los Angeles County to remain in the recovery phase until 2012. Historically, it will be the longest combined recession and recovery since World War II.

Variables in the Forecast

Population: A new United States Census was taken in April 2010. Local data is expected by June 2011. Historical population data is likely to be recast as interim data between forecasts is based on statistical studies. Los Angeles is a particularly difficult place to estimate population due to the highly transient nature of the citizenry. Los Angeles experiences high levels of foreign immigration and domestic out-migration. It was thought that the majority of out-migration was to Riverside and San Bernardino counties. Los Angeles renters moved to these counties to become homeowners. The housing crisis changed the migration pattern and there is uncertainty whether or not this long-time historical pattern will resume.

SB 375: SB 375 layers statewide guidelines onto local planning decisions. It favors redevelopment, known as brown field development, near transportation centers over new (green field) development. The goal is to reduce vehicle miles traveled thereby reducing emissions. Most development in Los Angeles is brown field development. However, brown field development is more complicated and expensive than green field development so overall development could slow. The City of LA's "Housing that Works" plan fits well into the SB 375 structure. Residential construction activity is forecasted to be historically slow during the recovery so it will take some time to see the ultimate outcome of SB 375 and the "Housing that Works" plan.

Emission Allowances: AB 32 seeks to reduce emissions to 1990 levels using a cap-and – trade scheme to begin in 2012. Program is designed to protect utilities and consumers but experience informs us that unintended consequences could arise as occurred during energy deregulation in the late 1990s.

Plug-in Hybrid Electric Vehicles (PHEV): The Forecast adopted the CEC forecast for PHEV adoption rate. LADWP is making PHEVs a key strategic initiative so adoption rates could be faster. On the other hand, there are competing technologies to PHEVs that the public may choose. Other credible forecasts including the United States Energy Information Administration have significantly lower forecasts for PHEV adoption citing problems with battery technology. The Forecast adapted an EPRI charging load profile for PHEVs. LADWP in-house strategies could significantly alter that charging profile.

Energy Efficiency: According to the State of California Strategic Plan, achieving the energy efficiency goals relies on new emerging technologies. The timing of the market availability and the adoption rates for the new technologies is unknown.

Smart Grid: It is unknown when LADWP will complete its Smart Grid program. Some believe that developing a Smart Grid system is a necessary precondition towards a successful PHEV program. Also Smart Grid is an important component towards achieving energy efficiency goals in the residential sector.

Vacancy Factor in Residential Sector: Vacancy rose faster than expected in the recession. Some of the vacancy rate was due to households combining and living in the same structure. Vacancy could rapidly swing lower as the economy begins to expand. The Forecast has vacancy rate returning to five percent which is the long-term average by 2015.

Vacancy Factor in Commercial Sector: High vacancy factor is expected to remain more persistent in the commercial sector as models for delivery of services especially in retail change. The rise of big-box retail stores and the Internet have crowded out the small retail shop owner over the past twenty years. There is a smaller need for a physical presence.

2011 RETAIL ENERGY AND DEMAND FORECAST

NET ELECTRICITY SALES BY CUSTOMER CLASS AND SYSTEM PEAK DEMAND WITH REGULATORY IMPACTS

	SECTOR SALES					Total Sales	LOSSES		Net					
Fiscal Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Miscellaneous* (GWh)	PHEV (GWh)	to Ultimate Customers (GWh)	Total (GWh)	DC Line (GWh)	Energy for Load (GWh)	Cogen (GWh)	Service Area Load (GWh)	Peak Demand (MW)[1]	Cogen (MW)	Service Area Peak (MW)
2000-01	7,542	12,107	2,754	531	0	22,934	2,753	319	25,688	1,294	26,981	5,299	184	5,483
2001-02	7,282	11,843	2,496	528	0	22,149	2,755	365	24,903	1,059	25,962	4,805	181	4,986
2002-03	7,358	12,077	2,383	545	0	22,363	3,006	437	25,370	1,069	26,438	5,185	184	5,369
2003-04	8,061	12,408	2,485	565	0	23,520	3,181	287	26,701	1,073	27,774	5,410	186	5,596
2004-05	7,907	12,374	2,447	551	0	23,279	3,059	294	26,338	1,075	27,413	5,418	187	5,605
2005-06	8,051	12,580	2,451	551	0	23,634	3,194	411	26,828	1,076	27,903	5,667	188	5,855
2006-07	8,495	12,984	2,332	567	0	24,378	3,125	426	27,502	1,077	28,579	6,102	191	6,293
2007-08	8,540	13,134	2,366	576	0	24,617	3,311	412	27,928	1,080	29,007	6,071	193	6,264
2008-09	8,578	13,084	2,303	560	0	24,526	2,921	418	27,447	1,084	28,531	6,006	196	6,202 [1]
2009-10	8,300	12,463	2,073	532	0	23,369	3,157	416	26,526	1,092	27,617	5,709	203	5,912
2010-11	8,181	12,268	2,116	485	1	23,051	2,913	416	25,965	1,105	27,070	6,142	212	6,354
2011-12	8,389	12,253	2,074	499	6	23,221	3,039	416	26,260	1,117	27,377	5,639	224	5,862
2012-13	8,359	12,248	2,063	491	14	23,175	2,982	416	26,157	1,139	27,295	5,635	239	5,873
2013-14	8,313	12,378	2,053	484	31	23,258	3,053	416	26,311	1,172	27,483	5,633	258	5,891
2014-15	8,419	12,627	2,057	477	62	23,641	3,031	416	26,672	1,209	27,881	5,725	277	6,002
2015-16	8,538	12,775	2,058	478	94	23,942	3,136	416	27,078	1,258	28,336	5,809	293	6,101
2016-17	8,647	12,916	2,058	479	120	24,221	3,110	416	27,331	1,287	28,618	5,891	306	6,196
2017-18	8,777	13,056	2,058	481	139	24,512	3,146	416	27,658	1,287	28,945	5,962	314	6,276
2018-19	8,920	13,199	2,059	483	166	24,826	3,185	416	28,010	1,287	29,297	6,041	319	6,359
2019-20	9,075	13,344	2,059	484	194	25,157	3,296	416	28,453	1,287	29,740	6,123	316	6,439
2020-21	9,231	13,536	2,060	486	236	25,549	3,270	416	28,820	1,287	30,107	6,211	319	6,530
2021-22	9,388	13,716	2,060	488	263	25,915	3,322	416	29,236	1,287	30,523	6,323	330	6,653
2022-23	9,536	13,834	2,060	490	287	26,207	3,365	416	29,572	1,287	30,859	6,396	337	6,732
2023-24	9,699	13,952	2,061	491	312	26,515	3,472	416	29,987	1,287	31,274	6,471	344	6,814
2024-25	9,867	14,070	2,061	493	336	26,826	3,442	416	30,268	1,287	31,555	6,549	354	6,902
2025-26	10,029	14,186	2,061	495	360	27,131	3,482	416	30,613	1,287	31,900	6,625	362	6,987
2026-27	10,192	14,302	2,062	497	384	27,436	3,521	416	30,957	1,287	32,244	6,701	368	7,069
2027-28	10,354	14,417	2,062	498	409	27,741	3,597	416	31,337	1,287	32,624	6,778	377	7,154
2028-29	10,513	14,529	2,063	500	432	28,037	3,563	416	31,600	1,287	32,887	6,838	386	7,224
2029-30	10,669	14,640	2,063	502	456	28,330	3,639	416	31,969	1,287	33,256	6,926	396	7,322
2030-31	10,830	14,756	2,064	504	481	28,634	3,680	416	32,313	1,287	33,600	7,000	401	7,401
2031-32	10,994	14,885	2,064	505	506	28,955	3,753	416	32,709	1,287	33,996	7,078	401	7,479
2032-33	11,156	15,016	2,064	507	529	29,272	3,724	416	32,995	1,287	34,282	7,157	401	7,558
2033-34	11,317	15,146	2,065	509	553	29,590	3,801	416	33,391	1,287	34,678	7,236	401	7,637
2034-35	11,480	15,275	2,065	510	577	29,908	3,842	416	33,750	1,287	35,037	7,314	401	7,715
2035-36	11,642	15,403	2,066	512	603	30,226	3,919	416	34,145	1,287	35,432	7,393	401	7,794
2036-37	11,802	15,531	2,066	514	626	30,539	3,888	416	34,427	1,287	35,714	7,472	401	7,873
2037-38	11,959	15,660	2,066	516	650	30,850	3,964	416	34,814	1,287	36,101	7,549	401	7,950
2038-39	12,113	15,788	2,067	517	674	31,159	4,005	416	35,165	1,287	36,452	7,626	401	8,027
2039-40	12,271	15,916	2,067	519	700	31,473	4,081	416	35,554	1,287	36,841	7,703	401	8,104

Table updated through December 2010

Annual Percent Change

	Residential	Commercial	Industrial	Miscellaneous	PHEV	Total Sales	Losses Total	DC Line	Net Energy for Load	Cogen (GWh)	Service Area Load	Peak Demand	Cogen (MW)	Service Area Peak
1991-2001	1.03%	0.55%	-1.02%	0.53%		0.50%			0.48%		0.57%	-0.02%		0.10%
2001-10	1.07%	0.32%	-3.11%	0.04%		0.21%			0.36%		0.26%	0.83%		0.84%
2010-16	0.47%	0.41%	-0.13%	-1.79%		0.40%			0.34%		0.43%	0.29%		0.53%
2010-20	0.90%	0.68%	-0.07%	-0.94%		0.74%			0.70%		0.74%	0.70%		0.86%
2009-30	1.26%	0.81%	-0.02%	-0.29%		0.97%			0.94%		0.93%	0.97%		1.08%
2009-40	1.31%	0.82%	-0.01%	-0.08%		1.00%			0.98%		0.97%	1.00%		1.06%

*****'Miscellaneous' includes Streetlighting, Owens Valley, and Intra-Departmental.

PEAK DEMAND - MW
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	MAXIMUM
2001-02	4799	4805	4681	4604	3694	3626	3632	3576	3421	3599	4177	4493	4805
2002-03	4910	4874	5185	4463	4039	3735	3878	3724	3932	3860	4782	4522	5185
2003-04	5337	5410	5273	4159	3825	3887	3632	3606	4080	5161	5316	4448	5410
2004-05	5402	5123	5418	4087	3701	3956	3848	3698	3583	3815	4629	4524	5418
2005-06	5667	5405	5093	4692	4040	3732	3709	3702	3677	3592	4587	5498	5667
2006-07	6102	5305	5656	4529	4406	3965	4023	3694	4214	4059	4840	4729	6102
2007-08	5341	6071	5917	4557	4052	3908	3908	3778	3868	4769	5303	6006	6071
2008-09	5128	5384	5472	5647	3997	4176	3707	3672	3706	5064	4761	4304	5647
2009-10	5569	5553	5709	4510	3794	3918	3925	3756	3597	3523	3818	4322	5709

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	MAXIMUM
2010-11	5511	5592	6142	4900	4457	3786	3813	3787	3787	4091	4409	4670	6142 [1]
2011-12	5252	5639	5254	4477	3947	3917	3810	3788	3784	4088	4407	4668	5639
2012-13	5249	5635	5251	4474	3945	3915	3803	3777	3777	4090	4408	4668	5635
2013-14	5238	5633	5250	4475	3937	3907	3859	3832	3832	4159	4482	4746	5633
2014-15	5315	5725	5336	4550	3995	3964	3908	3881	3881	4223	4549	4817	5725
2015-16	5383	5809	5415	4619	4046	4015	3956	3928	3929	4285	4615	4886	5809
2016-17	5449	5891	5492	4686	4096	4064	4002	3975	3974	4338	4672	4946	5891
2017-18	5512	5962	5559	4744	4143	4111	4052	4024	4024	4397	4735	5012	5962
2018-19	5581	6041	5632	4807	4194	4162	4104	4077	4076	4458	4800	5081	6041
2019-20	5653	6123	5710	4873	4249	4217	4160	4124	4132	4523	4870	5155	6123
2020-21	5731	6211	5792	4944	4307	4274	4232	4204	4203	4605	4958	5248	6211
2021-22	5829	6323	5896	5033	4381	4348	4280	4252	4251	4659	5016	5309	6323
2022-23	5896	6396	5964	5092	4431	4398	4330	4301	4300	4713	5075	5371	6396
2023-24	5964	6471	6034	5152	4482	4448	4381	4336	4351	4771	5136	5436	6471
2024-25	6035	6549	6107	5214	4536	4501	4432	4402	4401	4827	5197	5500	6549
2025-26	6104	6625	6179	5275	4588	4553	4482	4451	4451	4882	5256	5563	6625
2026-27	6173	6701	6249	5336	4640	4604	4532	4501	4501	4938	5317	5627	6701
2027-28	6243	6778	6321	5397	4692	4656	4571	4518	4540	4982	5364	5677	6778
2028-29	6297	6838	6377	5445	4733	4696	4630	4599	4598	5047	5433	5750	6838
2029-30	6377	6926	6459	5516	4793	4756	4678	4647	4646	5101	5492	5812	6926
2030-31	6444	7000	6528	5575	4843	4806	4730	4698	4698	5158	5553	5877	7000
2031-32	6515	7078	6601	5637	4897	4859	4773	4711	4740	5205	5603	5930	7078
3032-33	6574	7157	6661	5688	4941	4903	4835	4802	4802	5273	5677	6008	7157
2033-34	6660	7236	6748	5763	5005	4967	4887	4854	4854	5331	5739	6074	7236
2034-35	6732	7314	6822	5826	5060	5021	4939	4906	4906	5388	5801	6139	7314
2035-36	6804	7393	6895	5889	5114	5075	4981	4911	4947	5435	5851	6192	7393
2036-37	6861	7472	6954	5939	5157	5118	5043	5009	5008	5502	5923	6269	7472
2037-38	6946	7549	7040	6013	5221	5181	5094	5059	5059	5558	5984	6332	7549
2038-39	7016	7626	7112	6074	5273	5233	5145	5110	5110	5615	6044	6396	7626
2039-40	7087	7703	7184	6136	5326	5286	5186	5107	5151	5660	6093	6448	7703

[1]Weather Normalized for Fiscal Year 2010-11 is 5589 MW.

MINIMUM DEMAND - MW
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	AVERAGE
2001-02	1933	1944	1985	1927	1879	1988	2010	1936	1881	1932	1879	1942	1936
2002-03	2009	1986	2015	1940	1917	1984	1996	1996	1913	1858	1892	1996	1959
2003-04	2140	2187	2163	1808	1982	2030	2107	2103	1931	1926	1912	2095	2032
2004-05	2071	2171	2161	2061	2057	2108	1984	2083	1982	1944	1925	2035	2049
2005-06	2100	2187	2043	2083	2085	2128	2109	2074	2114	2041	2068	2122	2096
2006-07	2406	2246	2196	2093	2088	2242	2276	2170	2080	2036	2050	2152	2170
2007-08	2287	2289	2173	2146	2106	2114	2229	2190	2121	2125	2078	2192	2171
2008-09	2262	2347	2229	2182	2091	2155	2131	2135	2117	2022	2062	1997	2144
2009-10	2041	2172	2155	2049	2050	2170	2142	2107	2047	2015	2000	2066	2085

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	AVERAGE
2010-11	2084	1925	1981	2029	2045	2091	2101	2146	2130	2167	2190	2088	2081
2011-12	2280	2311	2182	2190	2126	2075	2100	2223	2128	2165	2188	2087	2171
2012-13	2279	2310	2180	2189	2125	2074	2096	2140	2124	2161	2184	2083	2162
2013-14	2274	2305	2176	2185	2121	2070	2127	2171	2155	2193	2216	2113	2176
2014-15	2308	2339	2208	2217	2152	2100	2154	2199	2183	2221	2244	2140	2205
2015-16	2337	2369	2236	2245	2179	2127	2180	2305	2210	2248	2272	2167	2240
2016-17	2366	2398	2264	2273	2206	2153	2205	2252	2235	2274	2298	2192	2260
2017-18	2393	2426	2290	2299	2232	2178	2233	2280	2263	2303	2327	2219	2287
2018-19	2423	2456	2318	2328	2260	2205	2262	2310	2293	2332	2357	2248	2316
2019-20	2455	2488	2349	2358	2289	2234	2293	2420	2324	2364	2389	2279	2353
2020-21	2488	2522	2381	2390	2320	2264	2332	2382	2364	2405	2431	2318	2383
2021-22	2531	2566	2422	2431	2360	2303	2359	2409	2391	2433	2458	2344	2417
2022-23	2560	2595	2449	2459	2387	2329	2386	2437	2419	2461	2487	2371	2445
2023-24	2589	2625	2478	2487	2415	2356	2415	2544	2447	2490	2516	2400	2480
2024-25	2620	2656	2507	2517	2443	2384	2442	2494	2476	2519	2545	2427	2503
2025-26	2650	2687	2536	2546	2472	2412	2470	2522	2503	2547	2574	2455	2531
2026-27	2680	2717	2564	2575	2499	2439	2498	2550	2532	2576	2603	2482	2560
2027-28	2710	2747	2593	2604	2527	2466	2519	2651	2553	2598	2625	2504	2592
2028-29	2734	2771	2616	2626	2549	2488	2552	2605	2586	2631	2659	2536	2613
2029-30	2769	2807	2649	2660	2582	2520	2578	2633	2613	2659	2687	2562	2643
2030-31	2798	2836	2677	2688	2609	2546	2607	2662	2642	2688	2716	2591	2672
2031-32	2829	2867	2707	2717	2638	2574	2630	2764	2666	2712	2741	2614	2705
3032-33	2854	2893	2731	2742	2662	2597	2665	2721	2701	2748	2777	2648	2728
2033-34	2891	2931	2767	2778	2696	2631	2693	2750	2730	2777	2807	2677	2761
2034-35	2923	2963	2797	2808	2726	2660	2722	2780	2759	2807	2837	2705	2790
2035-36	2954	2994	2826	2838	2755	2688	2745	2882	2783	2831	2861	2728	2824
2036-37	2979	3020	2850	2862	2778	2711	2779	2838	2817	2866	2896	2762	2846
2037-38	3016	3057	2886	2897	2812	2744	2807	2866	2845	2895	2925	2790	2878
2038-39	3046	3088	2915	2926	2841	2772	2835	2895	2874	2924	2955	2818	2907
2039-40	3077	3119	2944	2956	2869	2800	2858	2997	2897	2947	2978	2840	2940

NET ENERGY FOR LOAD- GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	2206	2338	2138	2109	1965	2044	2100	1830	1972	1966	2068	2168	24903
2002-03	2391	2324	2306	2096	2005	2076	2077	1854	2069	1957	2104	2111	25370
2003-04	2581	2621	2352	2262	1983	2139	2119	1964	2136	2069	2253	2221	26701
2004-05	2460	2444	2440	2175	2051	2187	2166	1912	2101	2020	2209	2172	26338
2005-06	2582	2572	2232	2221	2076	2154	2141	1927	2143	2015	2238	2527	26828
2006-07	2935	2589	2398	2187	2142	2227	2178	1972	2200	2091	2267	2318	27502
2007-08	2664	2760	2420	2267	2119	2222	2251	2079	2144	2132	2288	2580	27928
2008-09	2701	2703	2528	2406	2115	2240	2187	1962	2131	2069	2253	2152	27447
2009-10	2597	2523	2542	2176	2030	2201	2151	1917	2087	1985	2078	2239	26526

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	2373	2424	2311	2171	2069	2165	2121	1910	2086	2017	2149	2169	25965
2011-12	2484	2539	2327	2210	2046	2141	2119	1978	2084	2016	2148	2168	26260
2012-13	2482	2537	2325	2208	2045	2140	2115	1905	2080	2012	2144	2164	26157
2013-14	2478	2532	2321	2204	2041	2136	2146	1932	2110	2041	2175	2195	26311
2014-15	2514	2569	2354	2236	2071	2167	2173	1957	2137	2067	2203	2223	26672
2015-16	2546	2602	2384	2265	2097	2195	2200	2051	2164	2093	2230	2251	27078
2016-17	2577	2634	2414	2293	2123	2222	2226	2004	2189	2117	2256	2277	27331
2017-18	2607	2665	2442	2319	2148	2247	2253	2029	2216	2143	2284	2305	27658
2018-19	2640	2698	2472	2348	2174	2275	2283	2056	2245	2171	2313	2335	28010
2019-20	2674	2733	2504	2379	2203	2305	2314	2154	2275	2201	2345	2367	28453
2020-21	2710	2770	2538	2411	2233	2336	2354	2120	2315	2239	2385	2408	28820
2021-22	2757	2818	2582	2453	2271	2377	2381	2144	2341	2264	2413	2435	29236
2022-23	2789	2850	2612	2481	2297	2404	2408	2168	2368	2290	2440	2464	29572
2023-24	2821	2883	2642	2510	2324	2432	2437	2264	2396	2318	2469	2493	29987
2024-25	2854	2917	2673	2539	2351	2460	2465	2220	2424	2344	2498	2522	30268
2025-26	2887	2951	2704	2569	2378	2489	2492	2245	2451	2371	2526	2550	30613
2026-27	2920	2984	2735	2598	2405	2517	2520	2270	2479	2397	2554	2579	30957
2027-28	2953	3018	2765	2627	2432	2545	2542	2359	2500	2418	2577	2601	31337
2028-29	2978	3044	2789	2650	2453	2567	2575	2319	2532	2449	2610	2634	31600
2029-30	3016	3083	2825	2683	2485	2600	2602	2343	2559	2475	2637	2662	31969
2030-31	3048	3115	2855	2712	2511	2627	2631	2369	2587	2502	2666	2691	32313
2031-32	3082	3150	2886	2742	2538	2656	2654	2460	2610	2525	2690	2715	32709
3032-33	3109	3178	2912	2766	2561	2680	2689	2421	2644	2557	2725	2751	32995
2033-34	3150	3220	2950	2802	2595	2715	2718	2448	2673	2585	2755	2781	33391
2034-35	3184	3254	2982	2833	2623	2745	2747	2474	2702	2613	2784	2810	33750
2035-36	3218	3289	3014	2863	2651	2774	2770	2565	2725	2635	2808	2834	34145
2036-37	3245	3317	3039	2887	2673	2797	2805	2526	2758	2667	2842	2869	34427
2037-38	3285	3358	3077	2923	2706	2832	2833	2551	2786	2694	2871	2898	34814
2038-39	3318	3392	3108	2952	2734	2860	2861	2577	2814	2721	2900	2927	35165
2039-40	3352	3426	3139	2982	2761	2889	2884	2667	2836	2743	2923	2951	35554

TOTAL SALES TO ULTIMATE CUSTOMERS- GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	1971	1948	2055	1903	1845	1794	1827	1798	1738	1724	1657	1888	22149
2002-03	1977	1932	1977	2037	1819	1918	1849	1872	1678	1755	1691	1860	22363
2003-04	1948	2164	2200	2110	2027	1891	2006	1810	1735	1852	1843	1933	23520
2004-05	1991	2120	2116	2070	1895	1977	1969	1852	1778	1798	1756	1956	23279
2005-06	1998	2176	2151	2055	1874	2038	1985	1863	1831	1828	1781	2053	23634
2006-07	2234	2390	2304	2137	1953	1959	1983	1932	1852	1853	1850	1932	24378
2007-08	2147	2253	2365	2187	1986	1979	2005	2015	1896	1899	1855	2031	24617
2008-09	2383	2143	2300	2270	2079	1964	2007	2002	1799	1819	1836	1926	24526
2009-10	1982	2127	2253	2289	1867	1881	1947	1925	1759	1745	1711	1883	23369

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	1943	1987	2068	2110	1891	1960	1969	1879	1799	1770	1786	1888	23051
2011-12	2026	2114	2153	2043	1900	1890	1971	1884	1801	1770	1784	1885	23221
2012-13	2022	2111	2152	2040	1896	1886	1969	1882	1798	1764	1777	1878	23175
2013-14	2017	2109	2150	2039	1893	1884	1981	1897	1813	1780	1796	1900	23258
2014-15	2055	2150	2192	2079	1931	1921	2007	1924	1838	1803	1818	1923	23641
2015-16	2081	2178	2219	2105	1954	1945	2033	1950	1863	1826	1841	1947	23942
2016-17	2106	2205	2246	2130	1976	1966	2057	1973	1885	1847	1861	1969	24221
2017-18	2129	2231	2272	2154	1998	1989	2082	1999	1910	1870	1884	1993	24512
2018-19	2155	2259	2300	2181	2023	2014	2109	2026	1936	1895	1909	2018	24826
2019-20	2182	2289	2329	2209	2048	2040	2138	2056	1964	1922	1935	2045	25157
2020-21	2211	2320	2360	2238	2074	2067	2176	2094	2001	1957	1970	2080	25549
2021-22	2248	2359	2398	2274	2108	2101	2203	2120	2027	1981	1993	2104	25915
2022-23	2273	2385	2424	2299	2130	2124	2228	2146	2051	2004	2016	2127	26207
2023-24	2298	2412	2451	2325	2154	2148	2255	2173	2077	2029	2040	2152	26515
2024-25	2324	2440	2480	2351	2179	2174	2282	2200	2103	2053	2064	2176	26826
2025-26	2350	2468	2507	2377	2202	2198	2308	2226	2129	2077	2088	2200	27131
2026-27	2375	2495	2534	2403	2226	2222	2335	2253	2155	2101	2111	2224	27436
2027-28	2401	2523	2562	2429	2250	2247	2362	2281	2180	2125	2134	2248	27741
2028-29	2426	2550	2589	2454	2273	2271	2388	2306	2205	2148	2157	2271	28037
2029-30	2450	2576	2615	2479	2296	2295	2414	2331	2229	2171	2179	2294	28330
2030-31	2475	2603	2642	2505	2319	2319	2441	2358	2255	2196	2204	2319	28634
2031-32	2501	2631	2670	2532	2344	2344	2468	2388	2282	2222	2229	2344	28955
3032-33	2528	2660	2699	2558	2368	2369	2496	2414	2309	2247	2253	2369	29272
2033-34	2555	2689	2727	2585	2393	2395	2523	2442	2336	2272	2278	2395	29590
2034-35	2582	2718	2756	2612	2417	2420	2551	2469	2363	2298	2303	2420	29908
2035-36	2609	2746	2784	2639	2442	2445	2578	2499	2390	2323	2328	2445	30226
2036-37	2635	2775	2813	2666	2466	2469	2606	2524	2416	2348	2352	2469	30539
2037-38	2662	2803	2841	2692	2490	2494	2632	2551	2442	2373	2376	2494	30850
2038-39	2688	2831	2868	2718	2513	2518	2659	2578	2468	2398	2400	2518	31159
2039-40	2714	2860	2897	2744	2537	2543	2686	2608	2495	2423	2424	2543	31473

RESIDENTIAL SALES - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	608	659	640	661	582	622	653	654	568	559	520	557	7282
2002-03	600	673	670	678	595	618	652	647	560	560	530	576	7358
2003-04	639	773	787	746	641	682	701	688	596	595	578	635	8061
2004-05	630	726	745	731	620	680	724	687	600	606	552	606	7907
2005-06	640	772	771	712	610	659	701	685	625	649	583	644	8051
2006-07	774	919	838	750	629	669	724	733	631	624	576	628	8495
2007-08	694	812	838	799	646	694	734	761	664	634	593	670	8540
2008-09	758	859	815	816	692	706	731	735	636	616	581	634	8578
2009-10	665	793	820	819	675	696	712	725	629	598	560	607	8300

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	635	710	720	765	659	697	752	734	667	624	599	619	8181
2011-12	694	776	799	754	675	683	754	739	671	626	600	619	8389
2012-13	693	776	799	752	672	680	753	738	668	621	594	613	8359
2013-14	688	773	795	747	665	671	748	736	666	618	592	613	8313
2014-15	696	782	805	756	672	679	758	747	676	627	600	621	8419
2015-16	705	794	816	767	680	687	770	760	687	636	608	629	8538
2016-17	714	806	827	776	687	695	779	770	696	644	615	637	8647
2017-18	723	817	839	787	696	705	792	784	708	655	625	646	8777
2018-19	734	829	852	799	707	716	806	798	721	666	636	657	8920
2019-20	746	843	866	812	718	728	820	813	736	679	647	668	9075
2020-21	758	857	880	825	729	740	835	828	750	691	659	679	9231
2021-22	771	872	895	839	741	752	849	843	763	703	670	690	9388
2022-23	782	885	908	851	751	763	863	858	777	716	681	701	9536
2023-24	794	899	923	864	763	776	879	874	792	729	693	713	9699
2024-25	807	914	938	878	776	790	894	890	807	742	706	725	9867
2025-26	820	929	952	892	788	802	909	906	821	756	718	736	10029
2026-27	832	943	967	905	800	815	925	922	836	769	730	748	10192
2027-28	845	958	982	919	812	828	940	937	851	782	742	759	10354
2028-29	857	972	996	932	824	841	955	953	865	795	753	771	10513
2029-30	869	985	1010	945	835	853	970	968	879	807	765	782	10669
2030-31	881	999	1025	958	847	866	985	984	894	821	777	793	10830
2031-32	893	1014	1040	972	859	879	1001	1000	909	834	789	805	10994
3032-33	906	1028	1054	985	871	892	1016	1016	923	847	801	816	11156
2033-34	918	1043	1069	999	883	905	1031	1032	938	860	813	828	11317
2034-35	931	1057	1084	1012	894	917	1046	1048	953	873	825	839	11480
2035-36	943	1072	1098	1026	906	930	1062	1063	968	887	837	851	11642
2036-37	956	1086	1113	1039	918	943	1077	1079	982	900	848	862	11802
2037-38	968	1100	1127	1052	929	955	1091	1094	996	912	860	873	11959
2038-39	980	1114	1141	1065	940	967	1106	1110	1011	925	871	884	12113
2039-40	992	1128	1155	1078	952	979	1121	1125	1025	938	883	895	12271

COMMERCIAL SALES - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	1086	1025	1147	975	1020	952	916	887	936	931	902	1067	11843
2002-03	1141	983	1050	1091	989	1065	951	969	885	959	958	1036	12077
2003-04	1023	1140	1154	1101	1084	969	1073	862	943	979	1017	1064	12408
2004-05	1084	1124	1129	1099	989	1046	1013	934	956	954	964	1082	12374
2005-06	1097	1151	1121	1115	1019	1081	1027	958	959	952	984	1116	12580
2006-07	1201	1216	1181	1134	1093	1085	1009	968	999	997	1039	1063	12984
2007-08	1169	1171	1254	1130	1090	1062	1051	1022	1002	1023	1048	1111	13134
2008-09	1369	1035	1225	1200	1144	1055	1031	1033	950	958	1025	1061	13084
2009-10	1097	1066	1190	1240	980	1007	1016	983	924	957	964	1039	12463

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	1083	1061	1125	1118	1024	1010	1002	940	932	944	978	1051	12268
2011-12	1105	1107	1124	1067	1012	994	1003	940	931	943	977	1049	12253
2012-13	1103	1105	1123	1067	1012	995	1004	940	931	943	976	1049	12248
2013-14	1103	1106	1125	1071	1017	1001	1020	957	949	961	996	1070	12378
2014-15	1133	1136	1155	1100	1045	1028	1034	970	961	973	1008	1083	12627
2015-16	1147	1150	1168	1113	1057	1041	1046	982	972	985	1020	1096	12775
2016-17	1160	1163	1181	1125	1069	1052	1057	992	983	995	1031	1108	12916
2017-18	1172	1176	1194	1137	1081	1063	1068	1003	994	1006	1042	1120	13056
2018-19	1185	1189	1207	1150	1092	1075	1079	1014	1004	1017	1054	1133	13199
2019-20	1199	1202	1219	1162	1104	1086	1091	1025	1016	1028	1066	1146	13344
2020-21	1212	1215	1232	1174	1116	1097	1110	1045	1035	1048	1086	1166	13536
2021-22	1233	1236	1253	1194	1135	1117	1120	1054	1044	1057	1095	1177	13716
2022-23	1244	1247	1264	1205	1145	1126	1129	1063	1053	1066	1105	1187	13834
2023-24	1255	1258	1274	1215	1154	1135	1139	1072	1062	1075	1114	1198	13952
2024-25	1266	1269	1285	1225	1164	1145	1148	1081	1071	1084	1124	1208	14070
2025-26	1277	1280	1296	1235	1174	1154	1157	1090	1080	1093	1133	1218	14186
2026-27	1288	1291	1306	1246	1183	1164	1166	1099	1088	1101	1142	1229	14302
2027-28	1298	1302	1317	1256	1193	1173	1175	1107	1097	1110	1151	1239	14417
2028-29	1309	1312	1327	1265	1202	1182	1184	1116	1105	1118	1160	1248	14529
2029-30	1319	1323	1337	1275	1211	1191	1193	1124	1114	1126	1169	1258	14640
2030-31	1329	1333	1347	1285	1220	1200	1202	1133	1122	1135	1178	1269	14756
2031-32	1341	1345	1359	1296	1231	1211	1212	1143	1132	1146	1189	1281	14885
3032-33	1353	1357	1371	1307	1242	1221	1222	1153	1142	1156	1200	1292	15016
2033-34	1365	1369	1382	1319	1252	1231	1232	1163	1152	1166	1210	1304	15146
2034-35	1377	1381	1394	1330	1262	1241	1242	1173	1162	1176	1221	1315	15275
2035-36	1389	1393	1406	1341	1273	1251	1252	1182	1172	1186	1231	1327	15403
2036-37	1401	1405	1417	1352	1283	1261	1262	1192	1182	1196	1242	1338	15531
2037-38	1413	1417	1429	1363	1293	1271	1272	1202	1191	1206	1252	1349	15660
2038-39	1425	1429	1440	1374	1304	1281	1282	1212	1201	1216	1263	1361	15788
2039-40	1437	1441	1452	1385	1314	1291	1292	1221	1211	1226	1273	1372	15916

INDUSTRIAL SALES - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	232	217	219	217	199	182	217	213	195	194	194	218	2496
2002-03	187	225	205	219	189	199	192	212	195	195	163	203	2383
2003-04	237	202	210	229	242	197	186	213	152	231	199	187	2485
2004-05	229	218	192	190	245	208	190	188	182	195	193	218	2447
2005-06	209	198	216	180	206	251	207	175	204	187	173	245	2451
2006-07	209	205	233	203	187	166	204	188	175	186	187	190	2332
2007-08	232	214	220	209	206	176	175	184	185	195	167	202	2366
2008-09	206	201	210	202	194	158	201	188	171	203	185	184	2303
2009-10	171	218	196	180	163	134	177	174	167	148	147	199	2073

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	181	175	184	183	171	214	172	166	165	164	167	174	2116
2011-12	184	186	186	177	170	169	171	165	164	163	167	173	2074
2012-13	183	185	185	177	169	168	170	164	163	162	166	172	2063
2013-14	182	184	184	176	168	167	169	163	162	161	165	171	2053
2014-15	182	184	185	176	169	167	170	164	162	161	165	171	2057
2015-16	182	184	185	176	169	168	170	164	162	162	165	171	2058
2016-17	182	184	185	177	169	168	170	164	162	162	165	171	2058
2017-18	182	184	185	177	169	168	170	164	162	162	165	171	2058
2018-19	182	184	185	177	169	168	170	164	162	162	165	171	2059
2019-20	182	184	185	177	169	168	170	164	162	162	165	171	2059
2020-21	182	184	185	177	169	168	170	164	162	162	165	171	2060
2021-22	182	184	185	177	169	168	170	164	163	162	165	171	2060
2022-23	182	184	185	177	169	168	170	164	163	162	165	171	2060
2023-24	182	185	185	177	169	168	170	164	163	162	165	171	2061
2024-25	182	185	185	177	169	168	170	164	163	162	165	171	2061
2025-26	182	185	185	177	169	168	170	164	163	162	165	171	2061
2026-27	182	185	185	177	169	168	170	164	163	162	165	172	2062
2027-28	182	185	185	177	169	168	170	164	163	162	165	172	2062
2028-29	182	185	186	177	169	168	170	164	163	162	165	172	2063
2029-30	182	185	186	177	169	168	170	164	163	162	165	172	2063
2030-31	182	185	186	177	169	168	170	164	163	162	165	172	2064
2031-32	182	185	186	177	169	168	170	164	163	162	166	172	2064
3032-33	182	185	186	177	169	168	170	164	163	162	166	172	2064
2033-34	182	185	186	177	169	168	171	164	163	162	166	172	2065
2034-35	182	185	186	177	169	168	171	164	163	162	166	172	2065
2035-36	183	185	186	177	169	168	171	164	163	162	166	172	2066
2036-37	183	185	186	177	169	168	171	165	163	162	166	172	2066
2037-38	183	185	186	177	170	168	171	165	163	162	166	172	2066
2038-39	183	185	186	177	170	168	171	165	163	162	166	172	2067
2039-40	183	185	186	177	170	168	171	165	163	162	166	172	2067

R-1 wo LOW INCOME AND LIFE LINE SALES - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	442	492	470	490	423	454	470	482	407	406	370	403	5310
2002-03	432	503	492	505	427	449	469	472	432	435	406	447	5469
2003-04	499	616	627	596	498	531	542	539	460	462	453	501	6324
2004-05	500	583	599	589	487	534	570	545	467	476	431	477	6258
2005-06	507	624	625	574	482	520	557	551	496	520	461	515	6431
2006-07	630	759	687	610	503	536	577	589	501	492	458	510	6852
2007-08	558	663	685	649	512	551	584	610	527	500	468	534	6841
2008-09	609	702	660	660	547	553	567	574	490	475	445	487	6769
2009-10	513	621	640	640	514	530	535	549	472	449	414	450	6327

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	470	535	537	578	486	519	568	555	504	472	453	468	6144
2011-12	525	586	604	570	510	516	570	559	507	473	453	468	6341
2012-13	524	586	604	569	508	514	569	558	505	470	449	463	6318
2013-14	520	584	601	565	502	507	566	556	504	467	448	463	6283
2014-15	526	591	608	572	508	513	573	565	511	474	453	469	6363
2015-16	533	600	617	580	514	519	582	574	519	481	460	476	6454
2016-17	540	609	625	587	519	525	589	582	526	487	465	481	6536
2017-18	547	617	634	595	526	533	599	592	536	495	473	488	6634
2018-19	555	627	644	604	534	541	609	603	545	503	480	496	6742
2019-20	564	637	654	614	542	550	620	615	556	513	489	505	6859
2020-21	573	648	665	623	551	559	631	626	567	522	498	513	6977
2021-22	583	659	677	634	560	568	642	638	577	532	506	521	7096
2022-23	591	669	686	643	568	577	652	648	587	541	515	530	7207
2023-24	600	680	697	653	577	587	664	661	599	551	524	539	7331
2024-25	610	691	709	664	586	597	676	673	610	561	533	548	7458
2025-26	620	702	720	674	595	607	687	685	621	571	542	557	7580
2026-27	629	713	731	684	604	616	699	697	632	581	552	565	7703
2027-28	638	724	742	694	614	626	711	709	643	591	561	574	7826
2028-29	648	734	753	705	623	636	722	720	654	601	569	582	7946
2029-30	657	745	764	714	631	645	733	732	665	610	578	591	8064
2030-31	666	755	774	724	640	655	745	744	676	620	587	600	8186
2031-32	675	766	786	735	649	664	756	756	687	630	596	608	8310
3032-33	685	777	797	745	658	674	768	768	698	640	605	617	8432
2033-34	694	788	808	755	667	684	779	780	709	650	614	626	8554
2034-35	704	799	819	765	676	693	791	792	720	660	623	635	8677
2035-36	713	810	830	775	685	703	802	804	731	670	632	643	8800
2036-37	722	821	841	785	694	712	814	816	742	680	641	652	8920
2037-38	732	832	852	795	702	722	825	827	753	690	650	660	9039
2038-39	740	842	862	805	711	731	836	839	764	699	659	668	9156
2039-40	750	853	873	815	719	740	847	850	775	709	667	676	9275

LIFELINE SALES - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	30	36	32	36	29	34	33	37	28	31	26	30	382
2002-03	29	36	33	36	29	33	32	35	27	30	26	31	376
2003-04	31	40	38	38	30	36	34	37	29	32	27	33	406
2004-05	30	38	36	37	30	36	36	37	29	32	26	31	398
2005-06	30	39	36	36	28	34	33	36	30	34	28	32	398
2006-07	35	46	38	36	28	34	34	38	30	31	26	31	408
2007-08	32	41	39	40	30	35	35	40	32	32	28	34	419
2008-09	36	44	39	41	33	37	37	41	33	34	30	35	439
2009-10	34	43	43	46	38	41	41	44	37	36	32	36	473

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	37	43	42	46	39	43	44	43	39	36	35	36	481
2011-12	40	45	46	44	39	40	44	43	39	36	35	36	488
2012-13	40	45	46	44	39	40	44	43	39	36	35	36	486
2013-14	40	45	46	43	39	39	44	43	39	36	34	36	483
2014-15	40	45	47	44	39	39	44	43	39	36	35	36	489
2015-16	41	46	47	45	40	40	45	44	40	37	35	37	496
2016-17	42	47	48	45	40	40	45	45	40	37	36	37	503
2017-18	42	47	49	46	40	41	46	46	41	38	36	38	510
2018-19	43	48	50	46	41	42	47	46	42	39	37	38	519
2019-20	43	49	50	47	42	42	48	47	43	39	38	39	528
2020-21	44	50	51	48	42	43	49	48	44	40	38	39	537
2021-22	45	51	52	49	43	44	49	49	44	41	39	40	546
2022-23	45	51	53	49	44	44	50	50	45	42	40	41	554
2023-24	46	52	54	50	44	45	51	51	46	42	40	41	564
2024-25	47	53	55	51	45	46	52	52	47	43	41	42	574
2025-26	48	54	55	52	46	47	53	53	48	44	42	43	583
2026-27	48	55	56	53	46	47	54	54	49	45	42	43	593
2027-28	49	56	57	53	47	48	55	55	49	45	43	44	602
2028-29	50	56	58	54	48	49	56	55	50	46	44	45	611
2029-30	51	57	59	55	49	50	56	56	51	47	44	45	620
2030-31	51	58	60	56	49	50	57	57	52	48	45	46	630
2031-32	52	59	60	57	50	51	58	58	53	48	46	47	639
3032-33	53	60	61	57	51	52	59	59	54	49	47	47	649
2033-34	53	61	62	58	51	53	60	60	55	50	47	48	658
2034-35	54	61	63	59	52	53	61	61	55	51	48	49	667
2035-36	55	62	64	60	53	54	62	62	56	52	49	49	677
2036-37	56	63	65	60	53	55	63	63	57	52	49	50	686
2037-38	56	64	66	61	54	56	63	64	58	53	50	51	695
2038-39	57	65	66	62	55	56	64	65	59	54	51	51	704
2039-40	58	66	67	63	55	57	65	65	60	55	51	52	713

LOW INCOME SALES - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	66	62	69	62	66	62	75	67	66	56	60	56	767
2002-03	69	66	76	68	71	64	78	68	34	30	34	31	688
2003-04	40	43	50	41	42	40	47	41	39	33	32	30	477
2004-05	31	34	39	34	34	34	41	34	34	30	29	28	402
2005-06	33	35	38	30	30	29	32	27	27	25	26	25	358
2006-07	34	37	37	29	27	24	33	32	29	27	27	26	362
2007-08	31	33	37	33	30	30	34	34	32	27	28	29	379
2008-09	36	37	39	35	35	37	47	43	41	37	40	40	466
2009-10	48	52	61	55	51	49	57	52	51	43	47	48	613

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	58	58	68	63	62	59	61	59	54	50	48	50	689
2011-12	56	62	64	61	54	55	61	60	54	50	48	50	675
2012-13	56	62	64	61	54	55	61	59	54	50	48	49	673
2013-14	55	62	64	60	53	54	60	59	54	50	48	49	669
2014-15	56	63	65	61	54	55	61	60	54	50	48	50	678
2015-16	57	64	66	62	55	55	62	61	55	51	49	51	687
2016-17	58	65	67	63	55	56	63	62	56	52	50	51	696
2017-18	58	66	68	63	56	57	64	63	57	53	50	52	707
2018-19	59	67	69	64	57	58	65	64	58	54	51	53	718
2019-20	60	68	70	65	58	59	66	65	59	55	52	54	731
2020-21	61	69	71	66	59	60	67	67	60	56	53	55	743
2021-22	62	70	72	68	60	61	68	68	61	57	54	56	756
2022-23	63	71	73	68	60	61	69	69	63	58	55	56	768
2023-24	64	72	74	70	61	62	71	70	64	59	56	57	781
2024-25	65	74	75	71	62	64	72	72	65	60	57	58	794
2025-26	66	75	77	72	63	65	73	73	66	61	58	59	807
2026-27	67	76	78	73	64	66	74	74	67	62	59	60	820
2027-28	68	77	79	74	65	67	76	75	68	63	60	61	834
2028-29	69	78	80	75	66	68	77	77	70	64	61	62	846
2029-30	70	79	81	76	67	69	78	78	71	65	62	63	859
2030-31	71	80	82	77	68	70	79	79	72	66	63	64	872
2031-32	72	82	84	78	69	71	81	81	73	67	64	65	885
3032-33	73	83	85	79	70	72	82	82	74	68	64	66	898
2033-34	74	84	86	80	71	73	83	83	76	69	65	67	911
2034-35	75	85	87	81	72	74	84	84	77	70	66	68	924
2035-36	76	86	88	83	73	75	85	86	78	71	67	68	937
2036-37	77	87	90	84	74	76	87	87	79	72	68	69	950
2037-38	78	89	91	85	75	77	88	88	80	73	69	70	963
2038-39	79	90	92	86	76	78	89	89	81	74	70	71	975
2039-40	80	91	93	87	77	79	90	91	83	75	71	72	988

A-1 SALES - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	256	253	256	253	236	227	233	224	222	218	218	234	2829
2002-03	250	258	249	245	231	300	170	235	211	254	179	238	2820
2003-04	252	271	269	251	243	233	244	218	225	226	233	241	2906
2004-05	246	260	258	244	221	239	238	215	218	218	219	239	2816
2005-06	249	268	254	246	226	240	240	221	225	219	221	251	2861
2006-07	268	276	262	244	233	236	239	222	222	225	230	213	2871
2007-08	253	264	274	243	237	232	232	227	223	229	215	238	2866
2008-09	260	264	250	250	234	232	227	225	210	209	214	226	2802
2009-10	238	252	256	348	123	224	227	224	205	214	206	226	2743

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	237	238	248	244	221	227	235	222	216	215	219	233	2755
2011-12	249	255	259	246	231	228	235	223	216	215	219	233	2807
2012-13	248	254	259	246	230	228	235	222	216	214	218	232	2804
2013-14	248	254	259	246	231	228	237	225	219	217	222	236	2821
2014-15	253	260	265	251	236	233	240	228	221	220	224	239	2871
2015-16	256	263	268	254	238	236	243	231	224	222	227	241	2904
2016-17	259	266	271	257	241	238	245	233	226	225	229	244	2935
2017-18	262	269	274	260	243	241	248	236	229	227	232	247	2968
2018-19	265	272	277	263	246	244	251	239	232	230	234	250	3002
2019-20	268	275	280	266	249	247	254	242	235	233	237	252	3037
2020-21	271	279	283	269	252	249	258	246	239	237	241	257	3080
2021-22	275	283	288	273	256	253	261	249	241	239	244	259	3121
2022-23	278	286	290	276	258	256	263	251	244	242	246	262	3152
2023-24	280	289	293	278	261	258	266	254	246	244	248	264	3183
2024-25	283	292	296	281	263	261	269	257	249	247	251	267	3215
2025-26	286	294	299	284	266	263	271	259	251	249	253	270	3246
2026-27	289	297	302	286	268	266	274	262	254	251	256	272	3277
2027-28	291	300	304	289	270	268	277	265	256	254	258	275	3307
2028-29	294	303	307	292	273	271	279	267	259	256	260	277	3337
2029-30	297	306	310	294	275	273	282	270	261	258	263	279	3367
2030-31	299	308	313	297	278	275	284	272	264	261	265	282	3398
2031-32	302	311	316	300	280	278	287	275	267	263	268	285	3431
3032-33	305	314	319	302	283	281	290	278	269	266	270	288	3464
2033-34	308	317	322	305	285	283	293	281	272	269	273	290	3498
2034-35	311	320	325	308	288	286	295	283	275	271	276	293	3531
2035-36	314	324	328	311	290	288	298	286	277	274	278	296	3564
2036-37	316	327	331	314	293	291	301	289	280	276	281	298	3597
2037-38	319	330	334	316	296	294	304	291	283	279	283	301	3629
2038-39	322	333	336	319	298	296	306	294	285	282	286	304	3662
2039-40	325	336	339	322	301	299	309	297	288	284	289	306	3694

A-2 SALES - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	327	321	383	266	302	298	264	253	285	257	303	289	3549
2002-03	314	330	328	323	289	299	292	286	262	271	274	306	3574
2003-04	342	342	345	332	312	296	291	276	270	293	307	325	3732
2004-05	325	346	345	329	293	306	296	274	282	283	288	319	3686
2005-06	327	351	340	327	300	310	302	276	283	274	288	335	3713
2006-07	357	375	349	334	310	301	309	271	289	287	297	312	3792
2007-08	344	346	365	336	314	291	294	294	281	288	302	320	3775
2008-09	356	345	361	346	326	299	289	291	270	269	294	300	3745
2009-10	301	274	317	319	291	272	267	265	246	256	259	283	3349

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	287	288	303	305	279	327	294	277	273	275	283	303	3495
2011-12	320	323	328	311	295	290	294	277	273	275	283	303	3571
2012-13	319	322	327	311	294	290	294	277	272	274	283	302	3567
2013-14	319	322	328	312	295	291	298	281	277	279	287	308	3597
2014-15	327	330	336	319	303	298	302	285	280	282	291	311	3662
2015-16	330	334	339	323	306	302	305	288	283	285	294	315	3703
2016-17	334	337	343	326	309	305	308	291	286	288	297	318	3741
2017-18	337	341	346	330	312	308	311	294	289	291	300	321	3779
2018-19	341	344	350	333	315	311	314	297	292	294	303	324	3818
2019-20	344	348	353	336	318	314	318	300	295	297	306	328	3858
2020-21	348	352	357	340	322	317	323	305	300	302	312	333	3911
2021-22	354	357	362	345	327	322	326	308	303	305	314	336	3959
2022-23	357	360	365	348	329	325	328	311	306	307	317	339	3993
2023-24	360	364	368	351	332	328	331	313	308	310	320	342	4026
2024-25	363	367	372	354	335	330	334	316	311	312	322	345	4060
2025-26	366	370	375	357	338	333	336	318	313	315	325	348	4093
2026-27	369	373	378	360	340	336	339	321	316	317	327	351	4126
2027-28	372	376	381	362	343	338	342	324	318	320	330	353	4159
2028-29	375	379	384	365	346	341	344	326	321	322	333	356	4191
2029-30	378	382	386	368	348	343	347	329	323	325	335	359	4223
2030-31	380	385	389	371	351	346	350	331	326	327	338	362	4256
2031-32	384	388	393	374	354	349	353	334	329	330	341	365	4293
3032-33	387	392	396	377	357	352	355	337	332	333	344	368	4329
2033-34	390	395	399	380	360	355	358	340	334	336	347	372	4366
2034-35	394	398	402	383	363	357	361	343	337	339	350	375	4402
2035-36	397	402	406	386	365	360	364	346	340	342	352	378	4438
2036-37	400	405	409	390	368	363	367	348	343	344	355	381	4474
2037-38	404	408	412	393	371	366	370	351	346	347	358	384	4510
2038-39	407	412	416	396	374	369	373	354	348	350	361	387	4546
2039-40	410	415	419	399	377	372	376	357	351	353	364	390	4582

A-3 SALES - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	731	660	724	676	677	615	615	618	622	647	565	754	7905
2002-03	785	606	680	727	669	671	677	638	596	613	683	678	8023
2003-04	641	746	748	731	736	640	733	556	627	642	660	686	8146
2004-05	705	726	720	711	669	695	662	610	626	630	641	706	8101
2005-06	715	733	720	730	680	719	668	633	623	630	649	735	8236
2006-07	776	770	780	743	737	727	656	653	663	659	683	703	8552
2007-08	790	763	821	754	725	727	699	682	680	700	699	732	8774
2008-09	952	624	814	803	769	705	684	697	633	669	691	708	8749
2009-10	750	721	806	779	744	677	716	689	650	659	670	721	8582

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	753	718	770	763	700	696	652	612	603	611	634	681	8193
2011-12	715	718	730	693	658	647	652	612	603	610	633	680	7950
2012-13	714	717	729	692	658	647	652	611	602	609	632	679	7943
2013-14	713	717	730	694	660	650	661	621	612	620	643	691	8013
2014-15	730	734	747	711	677	666	669	628	619	627	651	698	8157
2015-16	738	742	755	718	684	673	676	635	626	633	657	706	8243
2016-17	746	750	762	726	690	680	683	641	632	639	664	713	8325
2017-18	753	757	770	733	697	686	689	648	638	645	670	720	8406
2018-19	760	765	777	740	704	693	696	654	644	652	677	727	8489
2019-20	768	772	785	747	711	699	702	660	651	659	684	735	8573
2020-21	776	780	792	754	717	706	714	672	662	670	695	747	8684
2021-22	788	792	804	766	729	717	719	677	668	675	701	753	8788
2022-23	794	799	810	772	734	723	725	682	673	680	707	759	8857
2023-24	801	805	816	778	740	728	730	688	678	686	712	765	8926
2024-25	807	811	823	784	746	734	735	693	683	691	717	771	8995
2025-26	813	818	829	790	751	739	741	698	688	696	723	777	9063
2026-27	820	824	835	796	757	744	746	703	693	701	728	783	9131
2027-28	826	830	841	801	762	750	752	709	698	706	734	789	9198
2028-29	832	837	847	807	768	755	757	714	703	711	739	794	9263
2029-30	838	843	853	813	773	761	762	719	708	716	744	800	9328
2030-31	844	849	859	819	778	766	767	724	713	721	750	806	9396
2031-32	851	855	866	825	785	772	773	730	719	727	756	813	9472
3032-33	858	863	873	832	791	778	779	735	725	733	762	820	9548
2033-34	865	870	879	838	797	784	785	741	731	739	768	826	9623
2034-35	872	877	886	845	803	790	791	747	737	745	774	833	9698
2035-36	879	884	893	851	809	796	797	753	742	750	780	840	9773
2036-37	886	891	900	858	815	801	803	758	748	756	786	846	9848
2037-38	893	898	907	864	821	807	808	764	754	762	793	853	9923
2038-39	900	905	913	870	827	813	814	770	760	768	799	859	9998
2039-40	907	912	920	877	833	819	820	775	765	774	805	866	10072

EXPERIMENTAL RATES - ELECTRICITY SALES - GWH
(Includes Real Time Pricing, Contract Demand, and Guarantee Load Factor)
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	85	89	89	87	80	72	105	83	76	77	83	87	1014
2002-03	64	99	86	100	71	80	89	105	84	89	56	94	1017
2003-04	110	72	89	100	120	85	79	107	51	126	90	79	1109
2004-05	118	94	83	88	129	97	89	101	88	94	87	118	1184
2005-06	98	84	105	75	96	148	111	83	111	92	73	122	1199
2006-07	96	90	113	103	83	73	98	92	83	97	91	99	1119
2007-08	100	100	105	97	103	77	90	89	85	87	80	108	1121
2008-09	96	91	101	94	98	65	120	95	88	91	87	93	1119
2009-10	60	124	93	65	65	54	72	68	68	55	50	88	863

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	67	73	70	76	73	58	84	81	80	80	82	86	910
2011-12	90	91	92	87	83	83	84	81	80	80	82	85	1018
2012-13	90	91	91	87	83	82	84	80	80	79	81	85	1013
2013-14	90	91	91	87	83	82	83	80	79	79	81	85	1011
2014-15	90	91	92	87	83	83	84	80	80	79	81	85	1016
2015-16	90	91	92	88	84	83	84	81	80	80	82	85	1018
2016-17	90	91	92	88	84	83	84	81	80	80	82	85	1020
2017-18	91	92	92	88	84	83	84	81	80	80	82	85	1022
2018-19	91	92	92	88	84	83	84	81	80	80	82	86	1024
2019-20	91	92	93	88	84	84	85	81	80	80	82	86	1026
2020-21	91	92	93	88	84	84	85	81	81	81	82	86	1029
2021-22	91	92	93	89	85	84	85	82	81	81	83	86	1031
2022-23	92	93	93	89	85	84	85	82	81	81	83	86	1033
2023-24	92	93	93	89	85	84	85	82	81	81	83	87	1034
2024-25	92	93	93	89	85	84	85	82	81	81	83	87	1036
2025-26	92	93	94	89	85	84	86	82	81	81	83	87	1038
2026-27	92	93	94	89	85	85	86	82	81	81	83	87	1040
2027-28	92	93	94	90	86	85	86	82	82	81	83	87	1041
2028-29	92	94	94	90	86	85	86	83	82	82	84	87	1043
2029-30	93	94	94	90	86	85	86	83	82	82	84	87	1045
2030-31	93	94	94	90	86	85	86	83	82	82	84	88	1046
2031-32	93	94	95	90	86	85	86	83	82	82	84	88	1048
3032-33	93	94	95	90	86	85	86	83	82	82	84	88	1050
2033-34	93	94	95	90	86	86	87	83	82	82	84	88	1052
2034-35	93	95	95	91	87	86	87	83	83	82	84	88	1054
2035-36	94	95	95	91	87	86	87	83	83	83	85	88	1055
2036-37	94	95	95	91	87	86	87	84	83	83	85	89	1057
2037-38	94	95	96	91	87	86	87	84	83	83	85	89	1059
2038-39	94	95	96	91	87	86	87	84	83	83	85	89	1061
2039-40	94	95	96	91	87	86	87	84	83	83	85	89	1063

RESIDENTIAL ACCUMULATED ENERGY EFFIENCY SAVINGS - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2029-2030
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	2	2	2	3	3	3	3	3	3	3	3	3	34
2002-03	3	4	4	4	4	4	3	4	4	4	4	4	45
2003-04	4	5	4	4	4	4	4	4	4	4	5	5	53
2004-05	5	5	5	5	5	5	5	5	5	5	6	6	62
2005-06	6	6	6	6	6	6	5	6	6	6	6	7	71
2006-07	7	7	7	7	7	7	7	7	7	7	8	8	86
2007-08	9	9	9	9	9	9	9	9	10	10	11	12	115
2008-09	13	13	13	13	12	12	14	16	21	22	23	25	195
2009-10	25	26	24	24	23	22	22	22	23	23	24	26	283

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	27	27	25	25	24	24	24	24	25	26	27	30	309
2011-12	31	31	30	29	28	28	27	28	29	30	32	34	357
2012-13	36	36	34	33	32	32	31	32	33	34	36	39	407
2013-14	40	40	37	36	34	33	33	33	34	34	36	39	430
2014-15	40	40	37	36	34	33	33	33	34	34	36	39	430
2015-16	40	40	37	36	34	33	33	33	34	34	36	39	430
2016-17	40	40	37	36	34	33	33	33	34	34	36	39	430
2017-18	40	40	37	36	34	33	33	33	34	34	36	39	430
2018-19	40	40	37	36	34	33	33	33	34	34	36	39	430
2019-20	40	40	37	36	34	33	33	33	34	34	36	39	430
2020-21	40	40	37	36	34	33	33	33	34	34	36	39	430
2021-22	40	40	37	36	34	33	33	33	34	34	36	39	430
2022-23	40	40	37	36	34	33	33	33	34	34	36	39	430
2023-24	40	40	37	36	34	33	33	33	34	34	36	39	430
2024-25	40	40	37	36	34	33	33	33	34	34	36	39	430
2025-26	40	40	37	36	34	33	33	33	34	34	36	39	430
2026-27	40	40	37	36	34	33	33	33	34	34	36	39	430
2027-28	40	40	37	36	34	33	33	33	34	34	36	39	430
2028-29	40	40	37	36	34	33	33	33	34	34	36	39	430
2029-30	40	40	37	36	34	33	33	33	34	34	36	39	430
2030-31	40	40	37	36	34	33	33	33	34	34	36	39	430
2031-32	40	40	37	36	34	33	33	33	34	34	36	39	430
3032-33	40	40	37	36	34	33	33	33	34	34	36	39	430
2033-34	40	40	37	36	34	33	33	33	34	34	36	39	430
2034-35	40	40	37	36	34	33	33	33	34	34	36	39	430
2035-36	40	40	37	36	34	33	33	33	34	34	36	39	430
2036-37	40	40	37	36	34	33	33	33	34	34	36	39	430
2037-38	40	40	37	36	34	33	33	33	34	34	36	39	430
2038-39	40	40	37	36	34	33	33	33	34	34	36	39	430
2039-40	40	40	37	36	34	33	33	33	34	34	36	39	430

COMMERCIAL ACCUMULATED ENERGY EFFIENCY SAVINGS - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2029-2030
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	26	27	26	26	26	26	27	28	30	31	33	37	343
2002-03	38	39	36	36	34	34	33	34	35	36	38	41	436
2003-04	43	43	40	39	37	37	36	37	38	38	40	44	472
2004-05	45	45	42	41	40	39	38	39	40	40	43	46	498
2005-06	47	48	45	44	42	41	40	41	42	43	45	49	525
2006-07	50	50	47	46	44	43	42	44	45	46	48	53	559
2007-08	54	55	51	51	48	47	46	48	49	51	55	62	618
2008-09	65	67	64	64	62	61	61	64	66	68	72	78	790
2009-10	82	83	78	77	74	73	72	74	77	78	85	93	946

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	96	97	92	91	87	85	83	86	87	89	94	102	1089
2011-12	105	106	100	98	94	93	91	94	97	99	105	114	1196
2012-13	117	118	111	109	105	103	101	105	107	109	116	125	1326
2013-14	128	128	120	117	111	108	105	108	109	111	117	125	1387
2014-15	128	128	120	117	111	108	105	108	109	111	117	125	1387
2015-16	128	128	120	117	111	108	105	108	109	111	117	125	1387
2016-17	128	128	120	117	111	108	105	108	109	111	117	125	1387
2017-18	128	128	120	117	111	108	105	108	109	111	117	125	1387
2018-19	128	128	120	117	111	108	105	108	109	111	117	125	1387
2019-20	128	128	120	117	111	108	105	108	109	111	117	125	1387
2020-21	128	128	120	117	111	108	105	108	109	111	117	125	1387
2021-22	128	128	120	117	111	108	105	108	109	111	117	125	1387
2022-23	128	128	120	117	111	108	105	108	109	111	117	125	1387
2023-24	128	128	120	117	111	108	105	108	109	111	117	125	1387
2024-25	128	128	120	117	111	108	105	108	109	111	117	125	1387
2025-26	128	128	120	117	111	108	105	108	109	111	117	125	1387
2026-27	128	128	120	117	111	108	105	108	109	111	117	125	1387
2027-28	128	128	120	117	111	108	105	108	109	111	117	125	1387
2028-29	128	128	120	117	111	108	105	108	109	111	117	125	1387
2029-30	128	128	120	117	111	108	105	108	109	111	117	125	1387
2030-31	128	128	120	117	111	108	105	108	109	111	117	125	1387
2031-32	128	128	120	117	111	108	105	108	109	111	117	125	1387
3032-33	128	128	120	117	111	108	105	108	109	111	117	125	1387
2033-34	128	128	120	117	111	108	105	108	109	111	117	125	1387
2034-35	128	128	120	117	111	108	105	108	109	111	117	125	1387
2035-36	128	128	120	117	111	108	105	108	109	111	117	125	1387
2036-37	128	128	120	117	111	108	105	108	109	111	117	125	1387
2037-38	128	128	120	117	111	108	105	108	109	111	117	125	1387
2038-39	128	128	120	117	111	108	105	108	109	111	117	125	1387
2039-40	128	128	120	117	111	108	105	108	109	111	117	125	1387

HUFFMAN BILL ACCUMULATED ENERGY EFFIENCY SAVINGS - GWH
2011 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2029-2030
FISCAL YEAR

HISTORICAL

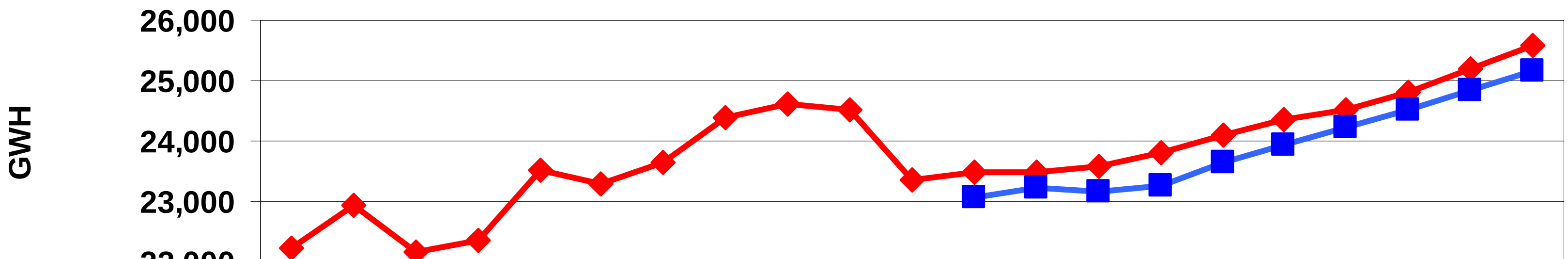
FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	0	0	0	0	0	0	0	0	0	0	0	0	0
2002-03	0	0	0	0	0	0	0	0	0	0	0	0	0
2003-04	0	0	0	0	0	0	0	0	0	0	0	0	0
2004-05	0	0	0	0	0	0	0	0	0	0	0	0	0
2005-06	0	0	0	0	0	0	0	0	0	0	0	0	0
2006-07	0	0	0	0	0	0	0	0	0	0	0	0	0
2007-08	0	0	0	0	0	0	0	0	0	0	0	0	0
2008-09	0	0	0	0	0	0	0	0	0	0	0	0	0
2009-10	0	0	0	0	0	0	0	0	0	0	0	0	0

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2010-11	0	0	0	0	0	0	0	0	0	0	0	0	0
2011-12	0	0	0	0	0	0	1	1	1	2	2	2	9
2012-13	3	3	4	4	5	6	7	8	9	10	10	9	77
2013-14	10	11	13	14	17	20	20	19	20	20	19	17	201
2014-15	18	18	21	22	25	29	29	26	27	27	25	22	287
2015-16	23	23	27	27	31	35	35	32	32	33	30	27	354
2016-17	27	27	32	32	36	41	40	36	37	37	34	29	408
2017-18	30	30	34	34	38	43	42	38	38	38	35	31	431
2018-19	31	31	35	36	39	45	44	40	40	40	36	32	448
2019-20	32	32	37	37	41	46	46	41	41	42	38	33	466
2020-21	34	34	39	39	43	49	49	44	44	44	40	35	494
2021-22	36	36	41	41	45	52	51	46	46	46	42	37	518
2022-23	37	37	43	43	47	54	53	47	47	48	43	38	536
2023-24	38	38	44	44	48	55	54	48	48	49	44	39	549
2024-25	39	39	44	44	49	56	55	49	49	49	45	39	556
2025-26	39	39	45	45	50	57	56	50	50	50	46	40	566
2026-27	40	40	46	46	50	57	56	51	51	51	46	41	575
2027-28	41	41	46	47	51	58	57	51	51	52	47	41	583
2028-29	41	41	47	47	52	59	58	52	52	52	48	42	592
2029-30	42	42	48	48	53	60	59	53	53	53	48	42	600
2030-31	42	42	48	49	53	61	60	54	54	54	49	43	609
2031-32	43	43	49	49	54	62	60	54	54	54	50	43	617
3032-33	43	44	50	50	55	62	61	55	55	55	50	44	625
2033-34	44	44	50	51	56	63	62	56	56	56	51	45	634
2034-35	45	45	51	51	56	64	63	57	57	57	52	45	642
2035-36	45	45	52	52	57	65	64	57	57	57	52	46	651
2036-37	46	46	53	53	58	66	65	58	58	58	53	46	659
2037-38	46	46	53	53	59	67	65	59	59	59	54	47	667
2038-39	47	47	54	54	59	68	66	60	60	60	54	48	676
2039-40	48	48	55	55	60	68	67	60	60	60	55	48	684

Retail Sales

- Key Change Factors from April 2010 to 2011
  - Balance Sheet Recession means lengthy recovery period.
  - Commercial vacancy rates remain high.
  - Construction activity remains at low level for extended period.
  - Higher electric prices to meet 33% renewable goal.
  - Includes Huffman Bill energy efficiency savings as a committed resource.



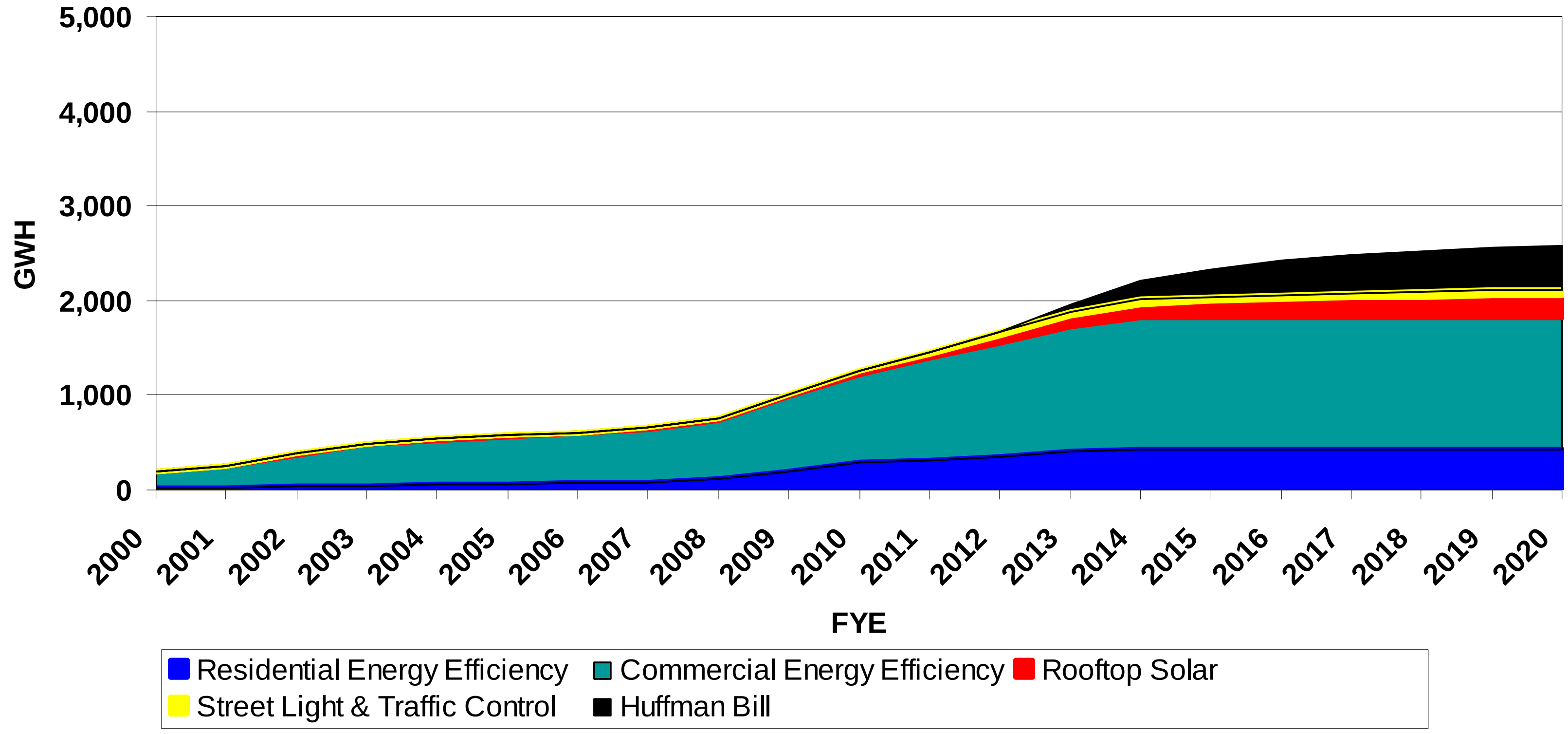
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
April 2010 Forecast	22,227	22,934	22,149	22,363	23,520	23,279	23,634	24,378	24,617	24,526	23,369	23,491	23,493	23,586	23,814	24,093	24,366	24,529	24,795	25,189	25,586
2011 Forecast												23,051	23,221	23,175	23,258	23,641	23,942	24,221	24,512	24,826	25,157

FYE

April 2010 Forecast — 2011 Forecast

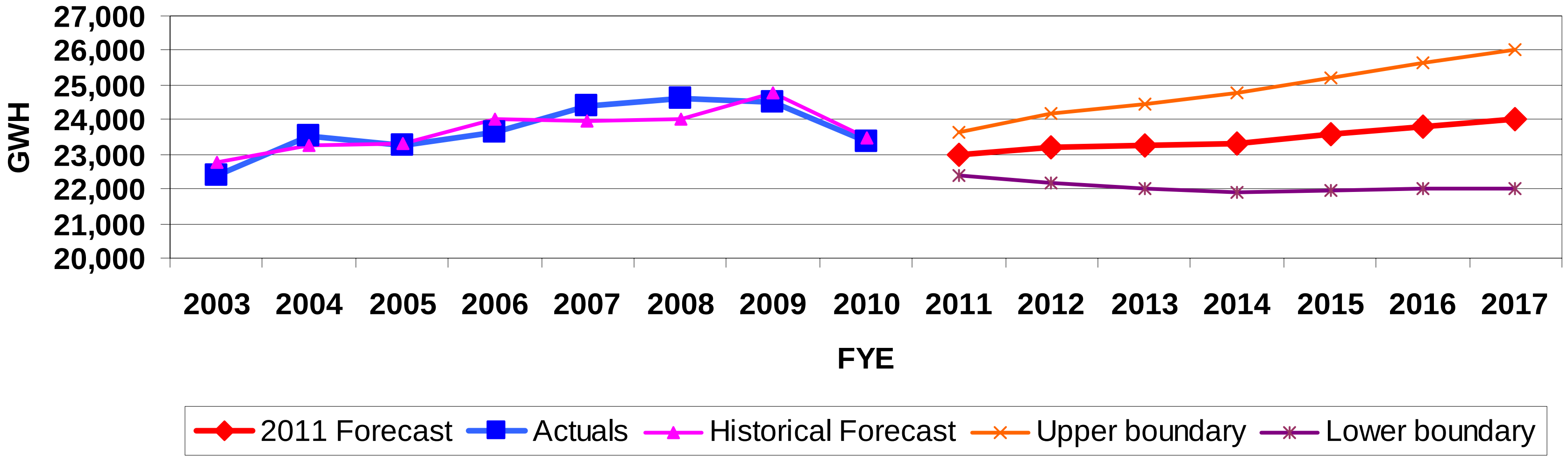
Forecasted Accumulated Savings Energy Efficiency and Solar Rooftops

- Components of Change
  - "Committed" LADWP EE programs through FYE 2013.
  - Huffman Bill savings.
  - "Uncommitted" EE will be accounted for as a resource.
  - Solar Rooftop Goal – 148 MW installed by 2020



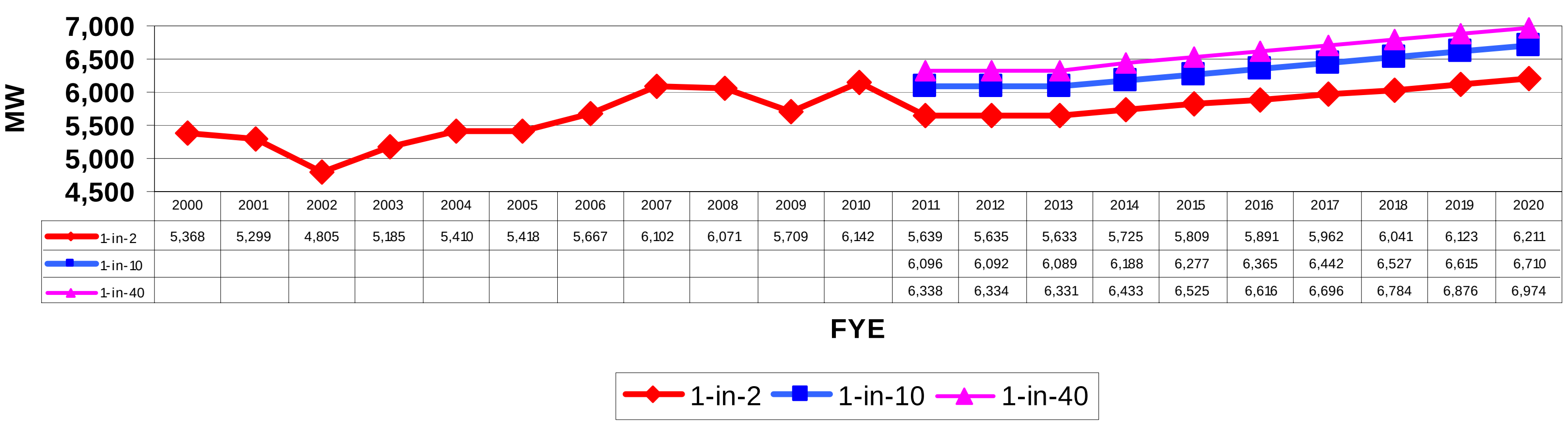
Retail Sales

- Accuracy
  - EE and Solar were not modeled explicitly in Historical Forecasts.
  - Historical accuracy is -0.1% with a 1.6% deviation. However expect larger variation in accuracy due to uncertainty of new programs.
  - Forecast variation is a function of weather, economic forecasts, meeting program goals and model specification.



Peak Demand

- Cases
  - The variance around the 1-in-2 forecasted peak has widened.
  - Climate change research expects more frequent heat storms to occur of longer duration.
  - Based on the climate change finding, it is now expected that the System will approach its potential more frequently so the distance between the 1-in-10 and 1-in-40 forecasts is compressed.



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1-in-2	5,368	5,299	4,805	5,185	5,410	5,418	5,667	6,102	6,071	5,709	6,142	5,639	5,635	5,633	5,725	5,809	5,891	5,962	6,041	6,123	6,211
1-in-10												6,096	6,092	6,089	6,188	6,277	6,365	6,442	6,527	6,615	6,710
1-in-40												6,338	6,334	6,331	6,433	6,525	6,616	6,696	6,784	6,876	6,974

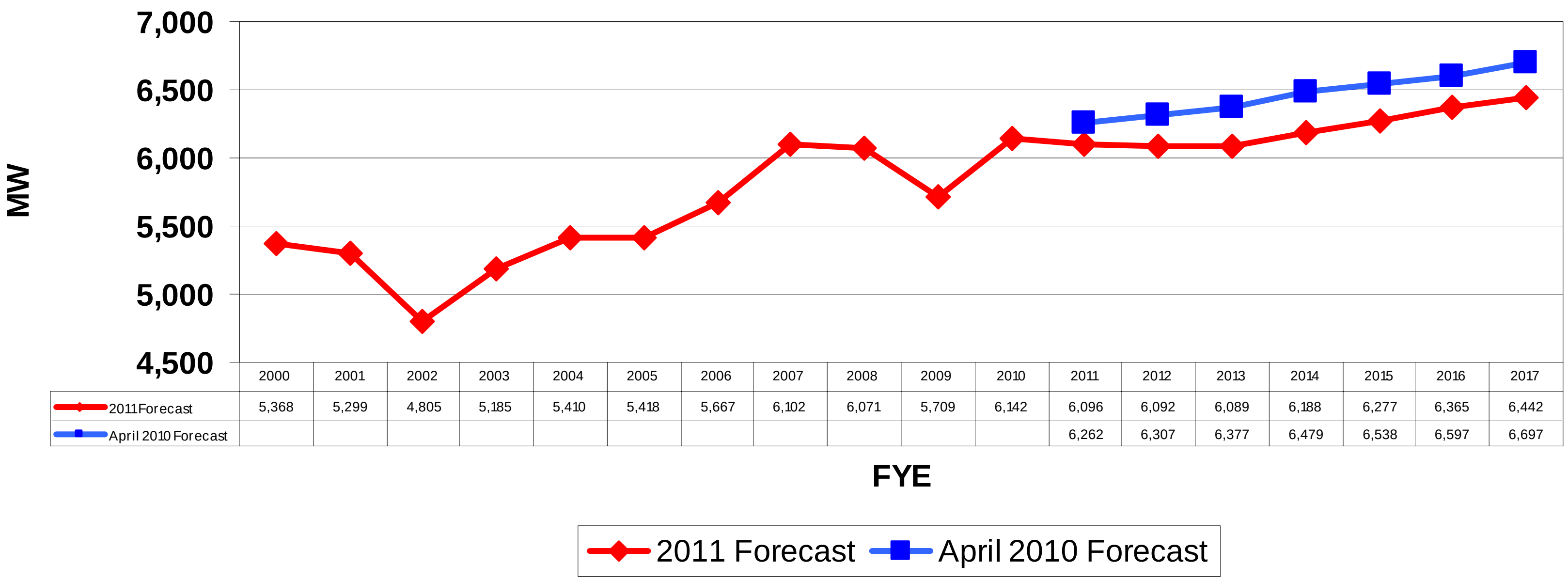
Peak Demand

- Annual peak demand is dependent on the severity of the heat storms that are encountered during the year.
- The cases are built on the probability of a weather event occurring in a given year.

Fiscal Year	Base Case	1 in 5	1 in 10	1 in 20	1 in 40
2011-12	5,589	5,887	6,042	6,171	6,282
2012-13	5,639	5,939	6,096	6,226	6,338
2013-14	5,635	5,935	6,092	6,222	6,334
2014-15	5,633	5,933	6,089	6,219	6,331
2015-16	5,725	6,030	6,188	6,320	6,433
2016-17	5,809	6,117	6,277	6,411	6,525
2017-18	5,891	6,203	6,365	6,500	6,616
2018-19	5,962	6,278	6,442	6,579	6,696
2019-00	6,041	6,360	6,527	6,665	6,784
2020-21	6,123	6,447	6,615	6,755	6,876
2021-22	6,211	6,539	6,710	6,852	6,974
2022-23	6,323	6,656	6,830	6,974	7,098
2023-24	6,396	6,733	6,909	7,055	7,181
2024-25	6,471	6,812	6,990	7,137	7,265
2025-26	6,549	6,894	7,074	7,223	7,352
2026-27	6,625	6,975	7,157	7,308	7,438
2027-28	6,701	7,054	7,238	7,391	7,523
2028-29	6,778	7,135	7,321	7,475	7,608
2029-30	6,838	7,198	7,385	7,541	7,676
2030-31	6,926	7,291	7,481	7,639	7,775
2031-32	7,000	7,369	7,560	7,720	7,857
2032-33	7,078	7,450	7,644	7,806	7,945
2033-34	7,157	7,534	7,730	7,894	8,034
2034-35	7,236	7,617	7,815	7,980	8,122
2035-36	7,314	7,700	7,900	8,067	8,210
2036-37	7,393	7,783	7,985	8,154	8,299
2037-38	7,472	7,865	8,070	8,240	8,387
2038-39	7,549	7,946	8,153	8,325	8,473
2039-40	7,626	8,027	8,236	8,410	8,559
2040-41	7,703	8,108	8,319	8,495	8,646

1-in-10 Peak Demand

- Resource Planning.
  - Weather-normalized peak in Summer 2010 was 5589 MW compared to the April 2010 forecast of 5797 MW.
  - The 1-in-10 Peak Demand Forecast is used in the Integrated Resource Plan.

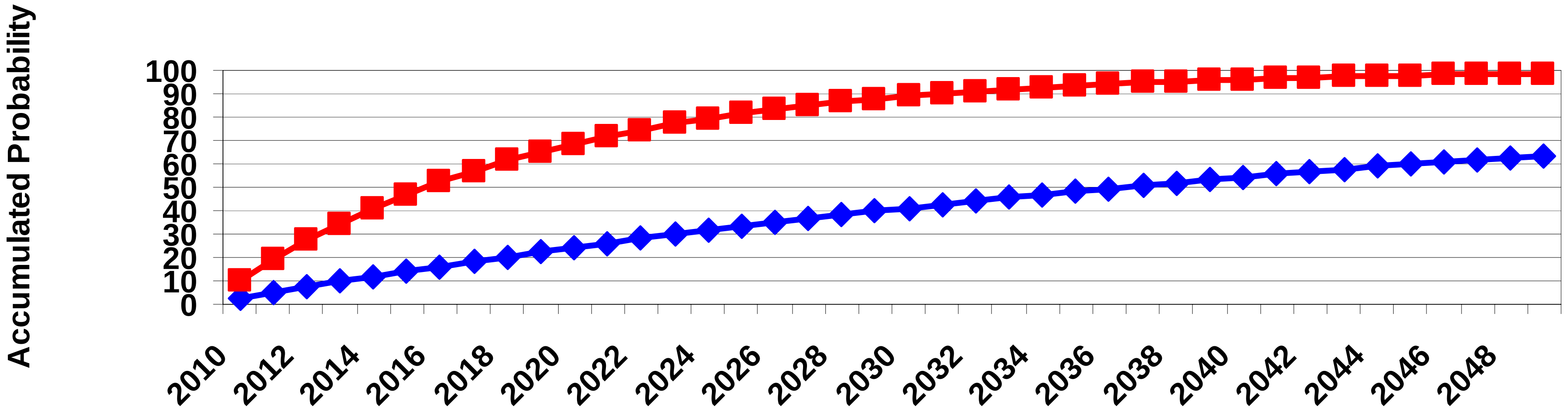


	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
2011 Forecast	5,368	5,299	4,805	5,185	5,410	5,418	5,667	6,102	6,071	5,709	6,142	6,096	6,092	6,089	6,188	6,277	6,365	6,442
April 2010 Forecast												6,262	6,307	6,377	6,479	6,538	6,597	6,697

1-in-10 Peak Demand

- Probability accumulates over time.
  - There is a 69% chance of having a 1-in-10 weather event by 2020.
  - There is a 24% chance of having a 1-in-40 weather event by 2020.
  - $P_t=1-(1-P_e)^t$

Probability over Time of a Weather Event



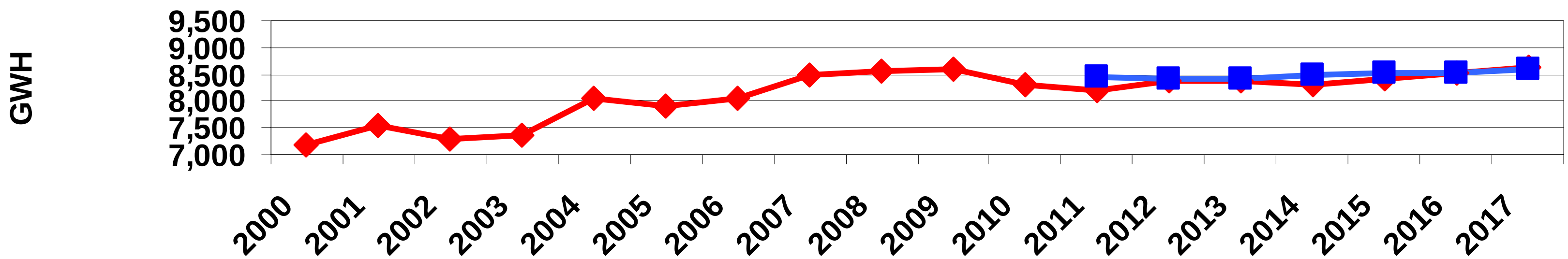
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
1-in-40	2.5	4.9	7.3	9.6	11.9	14.1	16.2	18.3	20.4	22.4	24.3	26.2	28.0	29.8	31.6	33.3	35.0	36.6	38.2	39.7
1-in-10	10.0	19.0	27.1	34.4	41.0	46.9	52.2	57.0	61.3	65.1	68.6	71.8	74.6	77.1	79.4	81.5	83.3	85.0	86.5	87.8

	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049
1-in-40	41.2	42.7	44.1	45.5	46.9	48.2	49.5	50.8	52.0	53.2	54.4	55.5	56.6	57.7	58.8	59.8	60.8	61.8	62.7	63.7
1-in-10	89.1	90.2	91.1	92.0	92.8	93.5	94.2	94.8	95.3	95.8	96.2	96.6	96.9	97.2	97.5	97.7	98.0	98.2	98.4	98.5

Year

Residential Energy Sales

- Components of Change
  - Higher weather response. All new units have air conditioning.
  - Fewer units built and higher vacancy factor.
  - Huffman Bill lighting impacts.



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
2011 Forecast	7,187	7,542	7,282	7,358	8,061	7,907	8,051	8,495	8,540	8,578	8,300	8,181	8,389	8,359	8,313	8,419	8,538	8,647
April 2010 Forecast												8,435	8,429	8,428	8,472	8,525	8,525	8,592

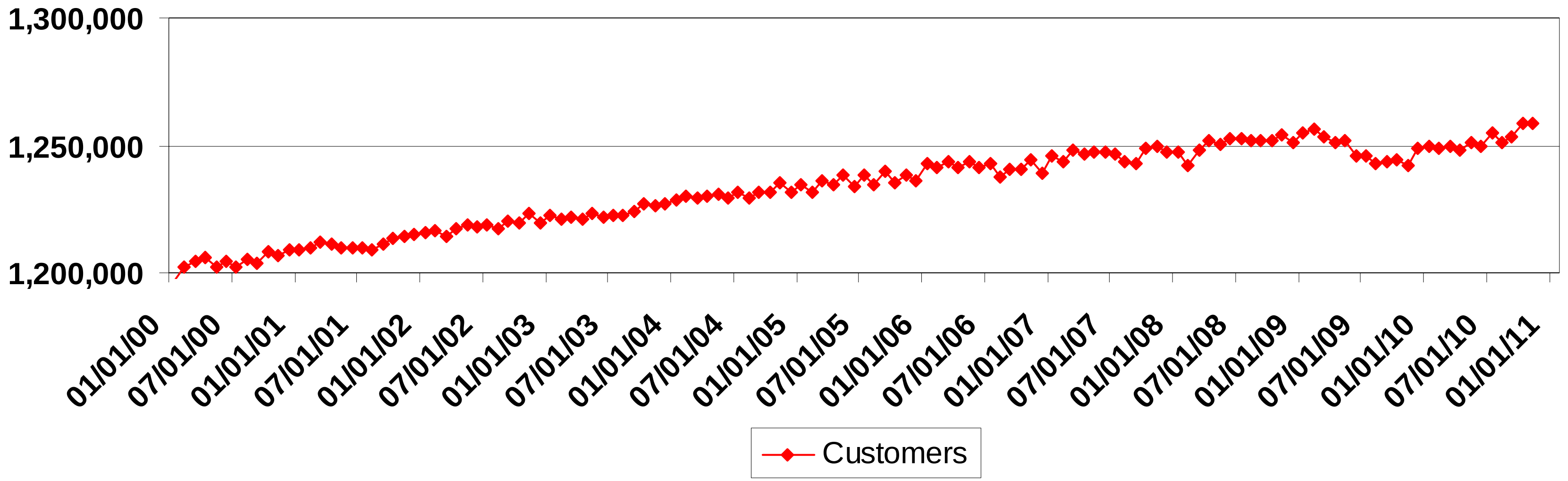
FYE

2011 Forecast April 2010 Forecast

Residential Energy Sales

Number of Residential Customers

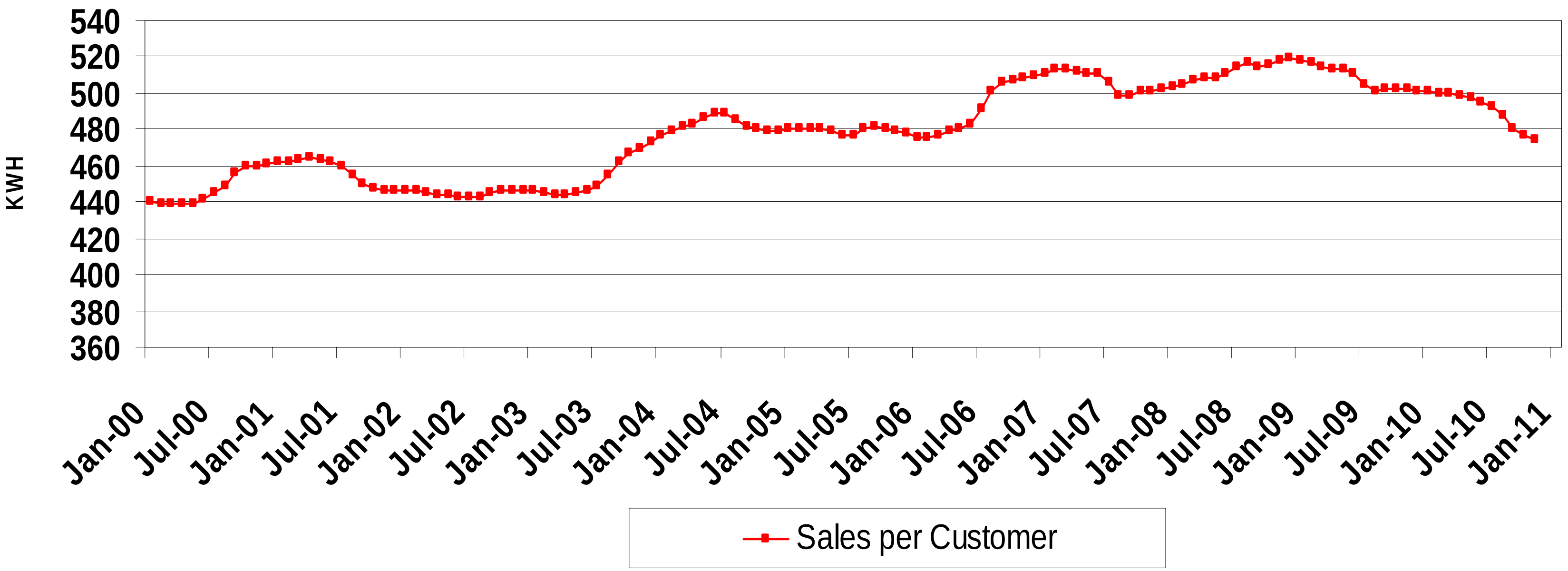
- Recent Evidence
  - Vacancy rising outstripping the growth in new units.
  - The majority of residential customers live in multi-family units.



Residential Sales

12-month Moving Average Sales per Customer

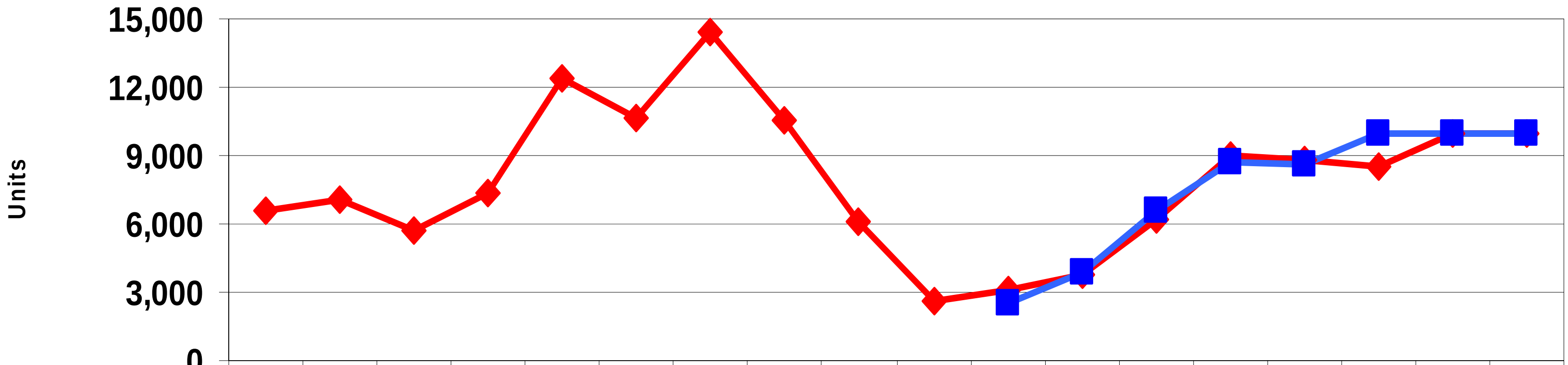
- Recent Evidence
  - Sales per residential customer reached an all-time high of 519 KWH per month in December 2008.
  - The November 2010 rate is 475 KWH per Month.
  - Replacing 2010 summer weather with normal adds 11 KWH to the November 2010 monthly rate.



Residential Energy Sales

New Residential Building Units

- Housing Forecast fundamentally unchanged.
- New units are 20% Single-Family and 80% Multi-family which lowers future average consumption per household.

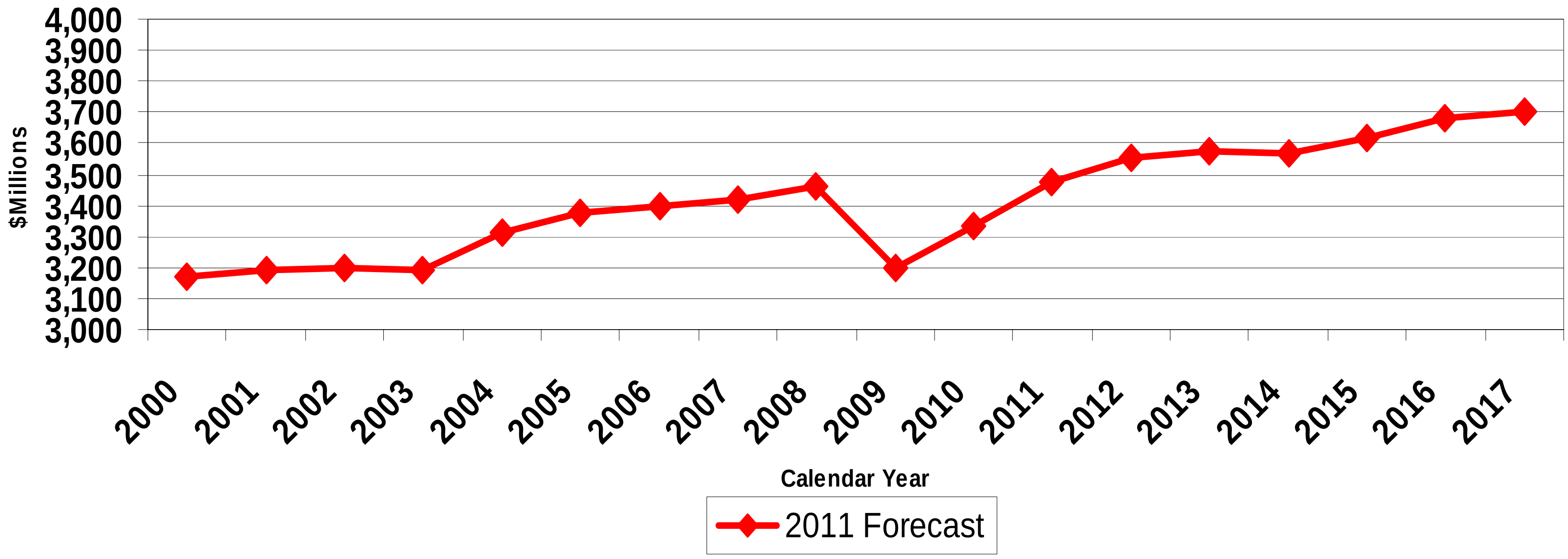


	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
2011 Forecast	6,567	7,062	5,673	7,361	12,340	10,666	14,448	10,554	6,080	2,607	3,129	3,820	6,239	8,961	8,814	8,512	10,000	10,000
April 2010 Forecast											2,534	3,839	6,549	8,758	8,640	10,000	10,000	10,000

Residential Energy Sales

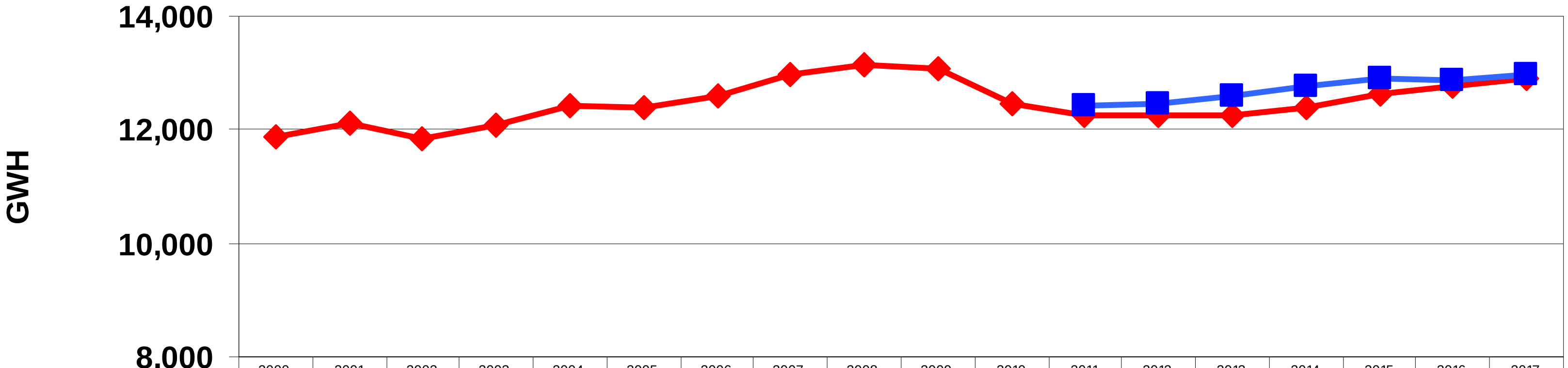
Recent Economic Impact

- Real Personal Consumption.
  - Recovery ends and expansion begins in 2012.



Commercial Energy Sales

- Components of Change
  - Commercial construction activity down.
  - Service employment forecast down slightly.
  - Higher real electric prices.
  - Committed energy efficiency included only through 2013. Some forecasted sales beyond 2013 will not be realized at the meter.



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
2011 Forecast	11,858	12,107	11,843	12,077	12,408	12,374	12,580	12,984	13,134	13,084	12,463	12,268	12,253	12,248	12,378	12,627	12,775	12,916
April 2010 Forecast												12,424	12,473	12,601	12,771	12,889	12,876	12,958

FYE

2011 Forecast April 2010 Forecast

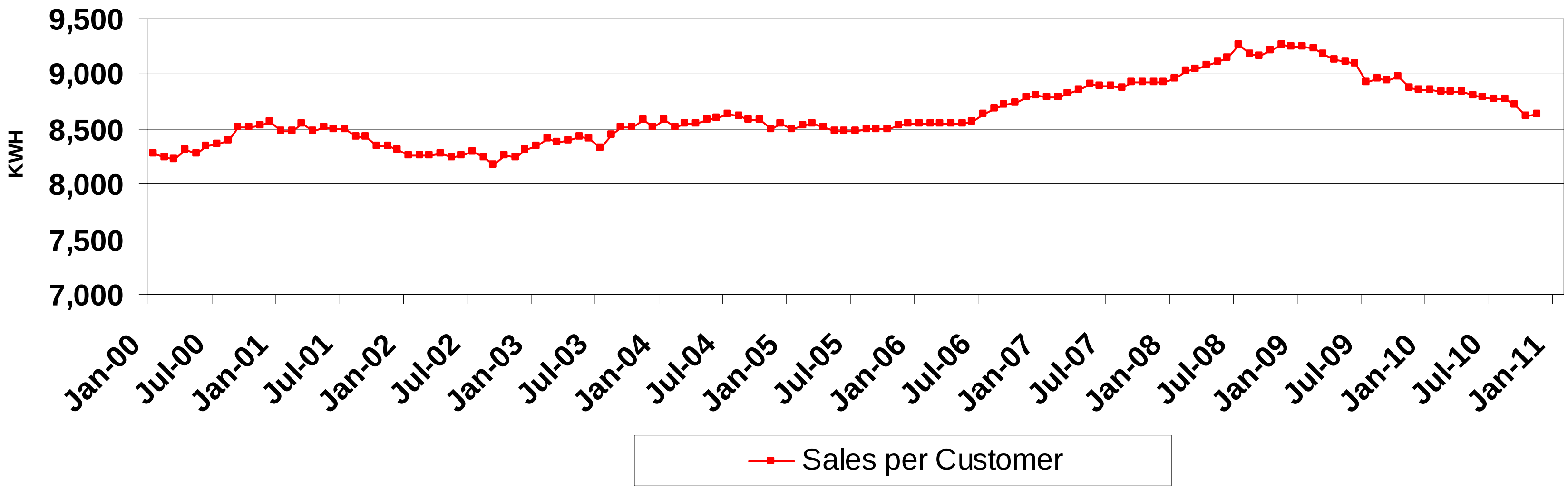
Commercial Energy Sales
Number of Commercial Customers

- Recent Evidence
  - The number of commercial customers peaked in June 2006.

Commercial Energy Sales

Twelve-Month Moving Average Sales per Customer

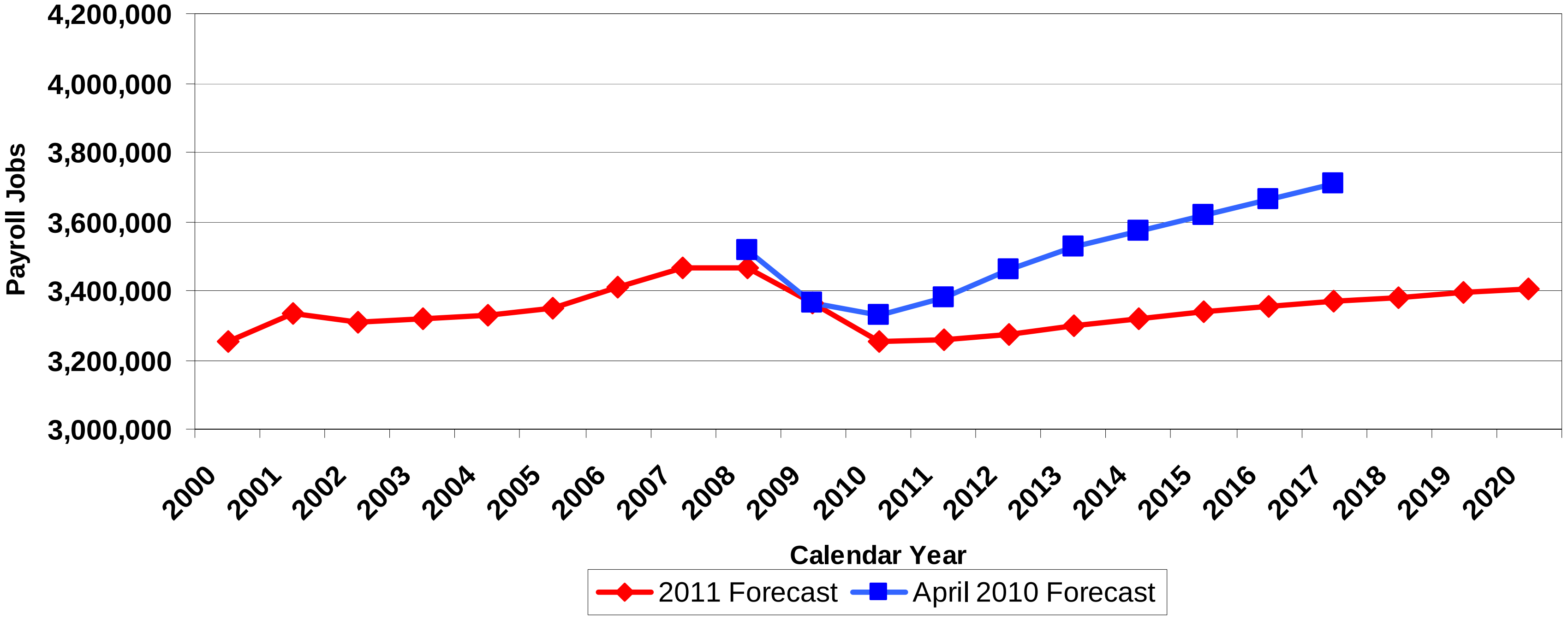
- Recent Evidence
  - Sales per customer per month peaked in July 2008 at 9265 KWH per month.
  - Currently sales per customer per month are 8639 KWH.
  - Adjusting to normal summer weather for 2010 adds 262 KWH to current sales per customer.



Commercial Energy Sales

Local Employment in Service Sector

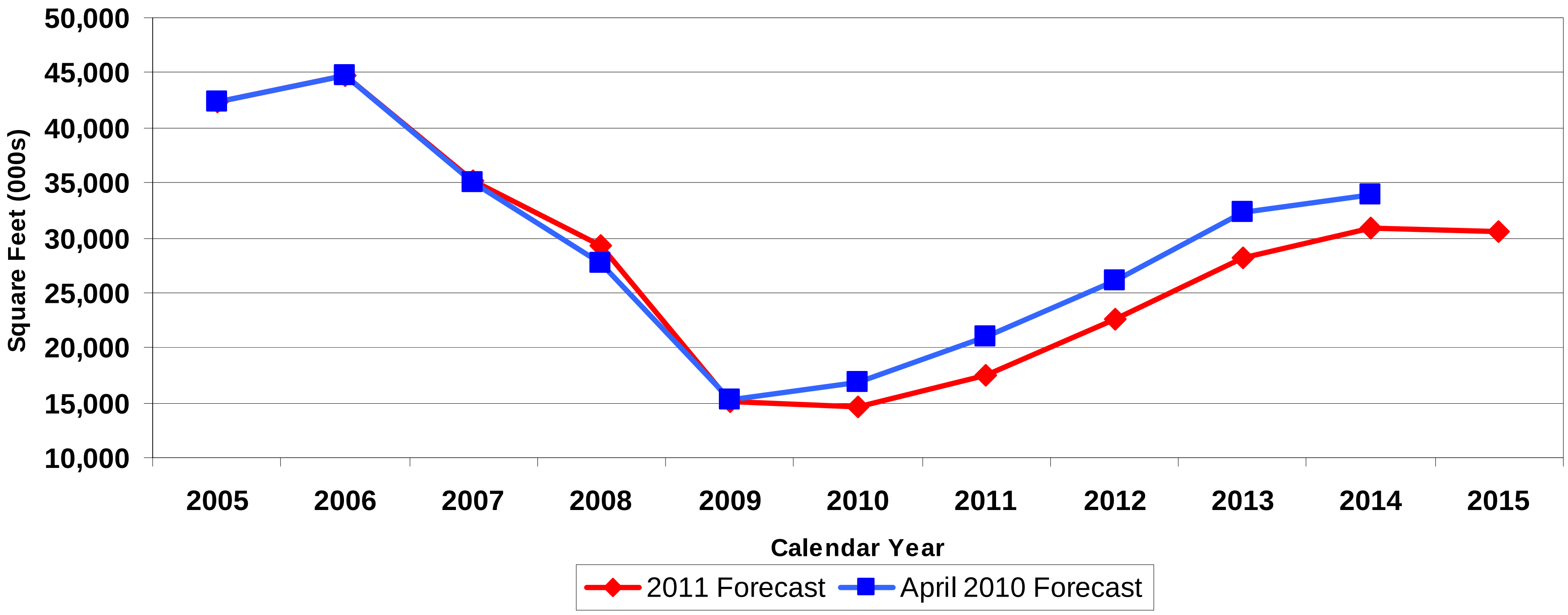
- LA County Commercial Services Employment
  - Balance Sheet Recession
  - Employment does not return to former level by 2020.



Commercial Energy Sales

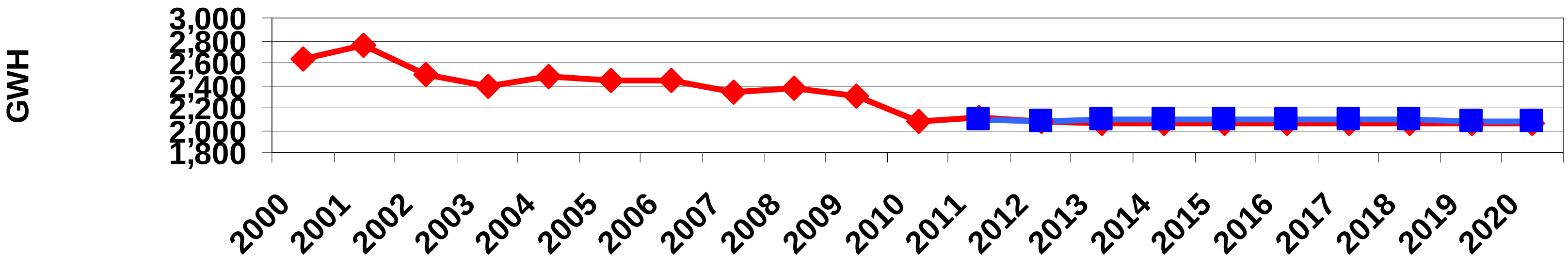
McGraw-Hill Construction Forecast

- Commercial Floorspace Additions
  - Construction activity at historically low levels.
  - Office vacancy rates in San Fernando Valley at 18 percent.
  - New models for delivering commercial services require smaller physical presence.
    - Big Box retailers
    - Internet



Industrial Energy Sales

- Components of Change
  - Land use issue: Once industrial land is vacated, residential and commercial building tend to replace it. 3 percent vacancy rates in the industrial sector.
  - Manufacturing continues to move offshore.
  - Higher real electric prices.
  - No EE or rooftop solar in the Industrial Forecast. All EE and solar assigned to Residential, Commercial and Streetlight sectors.



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2011 Forecast	2,637	2,754	2,496	2,383	2,485	2,447	2,451	2,332	2,366	2,303	2,073	2,116	2,074	2,063	2,053	2,057	2,058	2,058	2,058	2,059	2,059
April 2010 Forecast												2,087	2,081	2,097	2,099	2,098	2,098	2,094	2,087	2,084	2,084

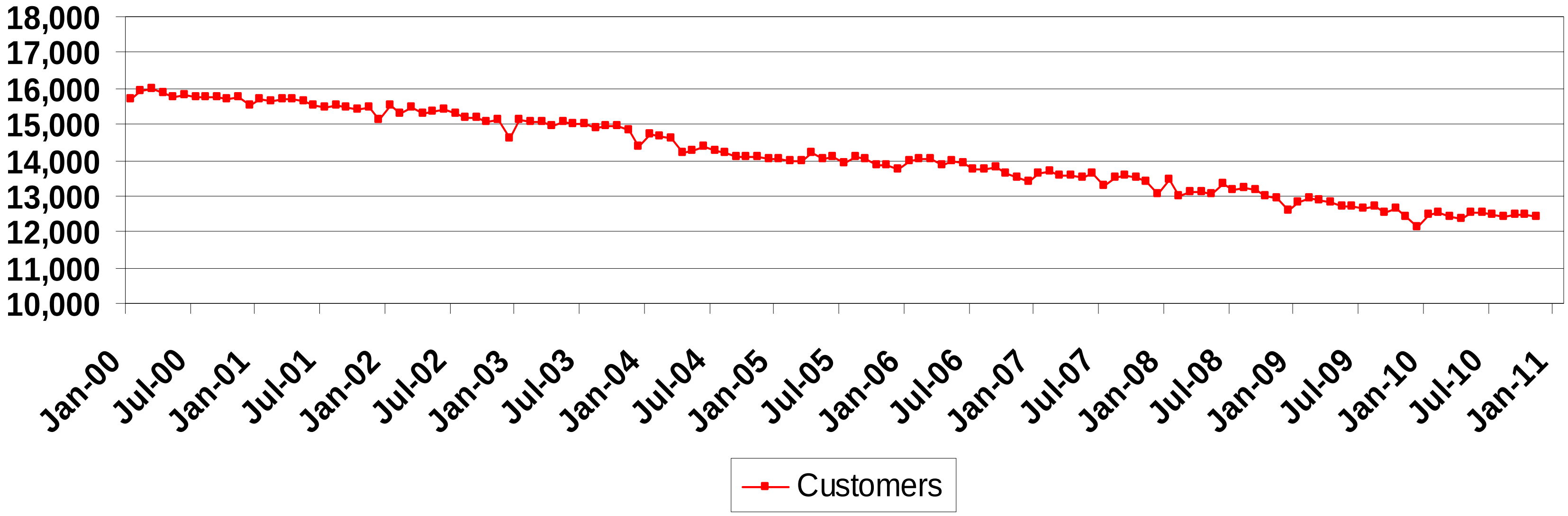
FYE

2011 Forecast — April 2010 Forecast

Industrial Energy Sales

Number of Customers

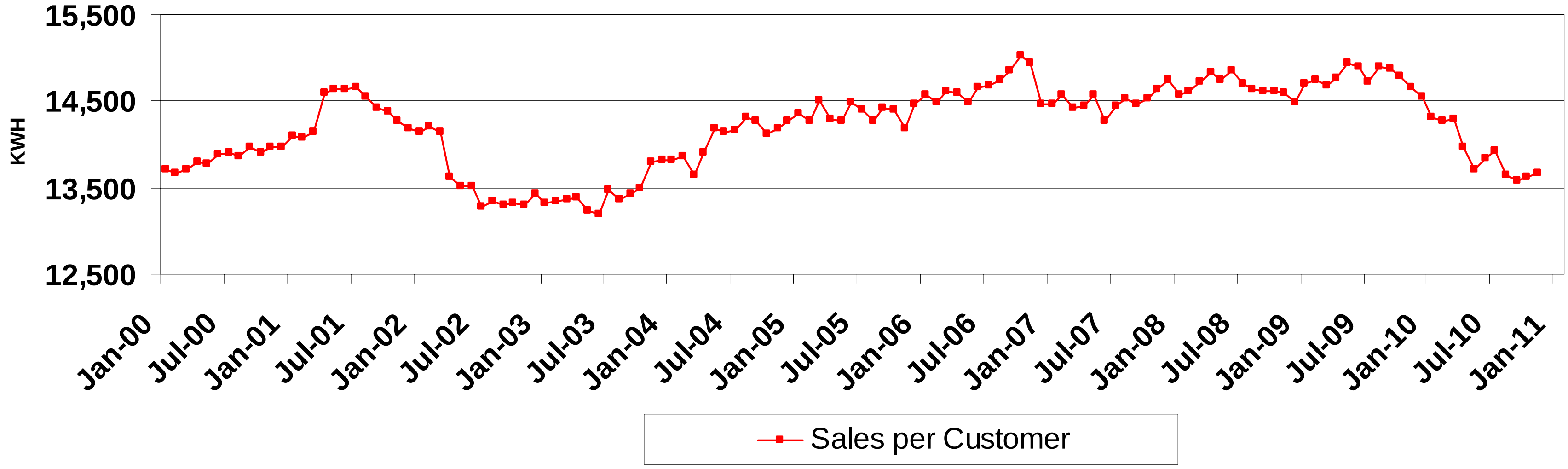
- Recent Evidence
  - The number of Industrial customers is continually and relentlessly declining.
  - The decline began in the 1970s**.**
  - The forecast is for the heavy industries to remain although no new heavy industry will be built. It is the light industry and assembly jobs that are disappearing.



Industrial Sales

Twelve-Month Moving Average Sales per Customer

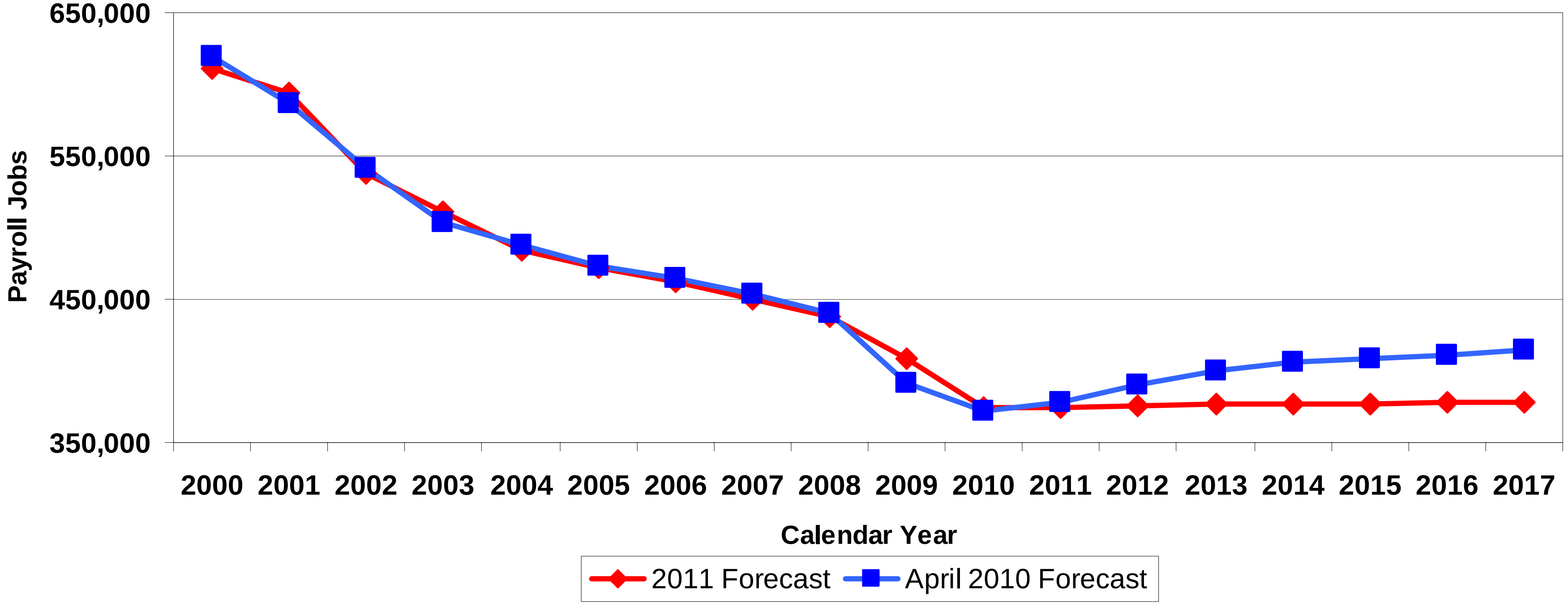
- Recent Evidence
  - Sales per customer per month peaked in October 2006 at 15018 KWH per month. High consumption partially attributed to a large self-generation unit being off-line at a refinery.
  - Currently sales per customer per month are 13666 KWH.



Industrial Sales

Employment Outlook

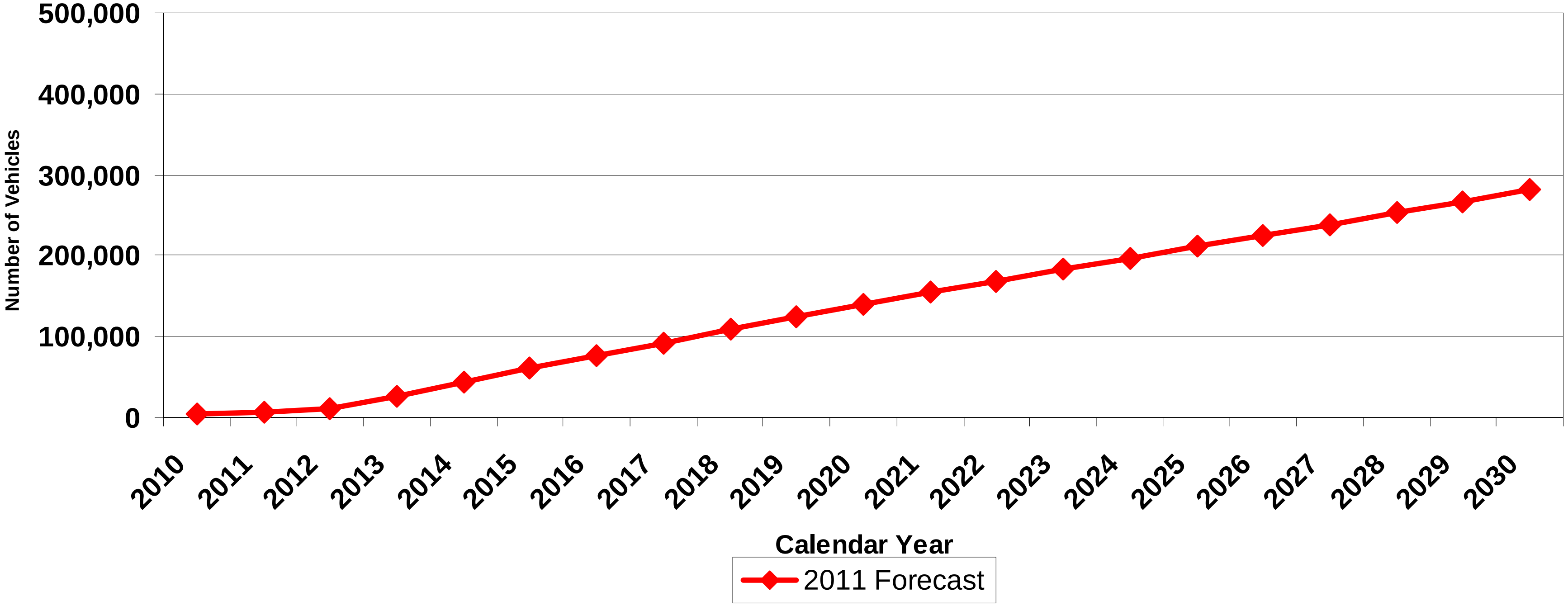
- LA County Manufacturing Employment
  - Future employment forecast is slightly positive. If Los Angeles continues to lose manufacturing jobs then there will be a mismatch with the education level of the population and available high paying jobs. It could lead to significant population out-migration.



Plug-in Hybrid Electric Vehicles

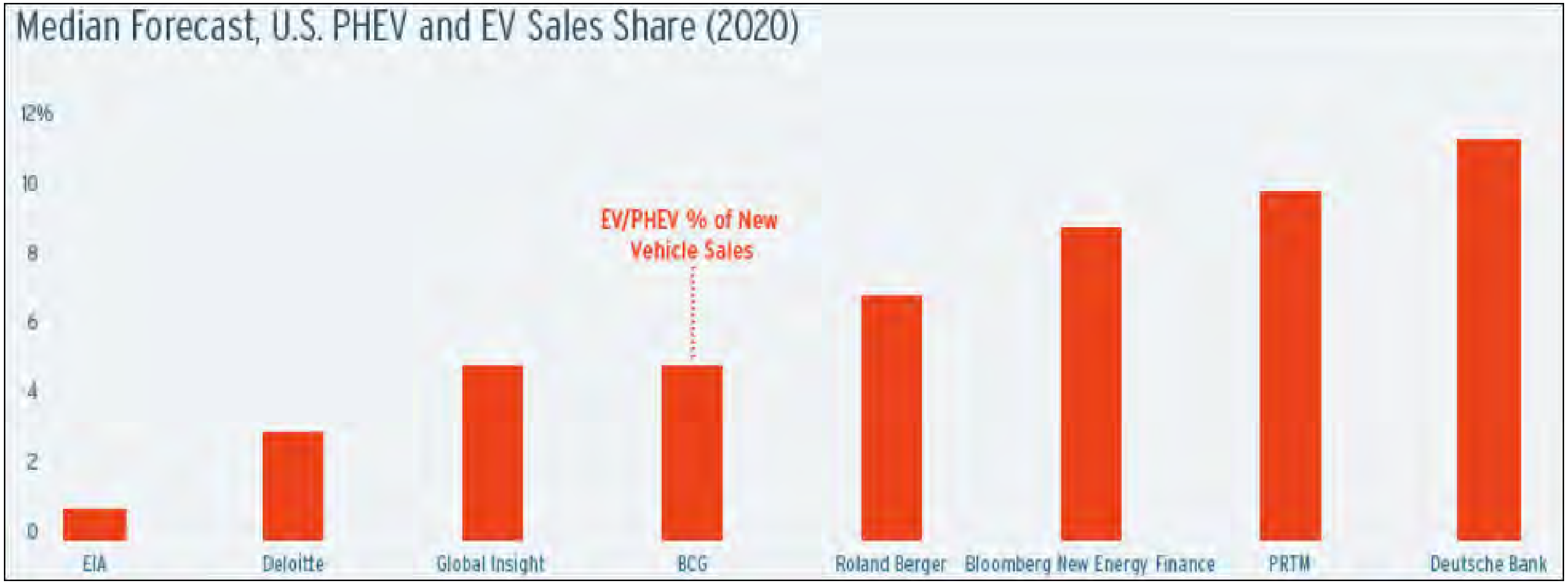
Potential New Load Growth

- Adopted the California Energy Commission Forecast.
- Forecast dependent on:
  - Improved battery technology.
  - Implementation of Smart Grid.
  - Implementation of Charging stations



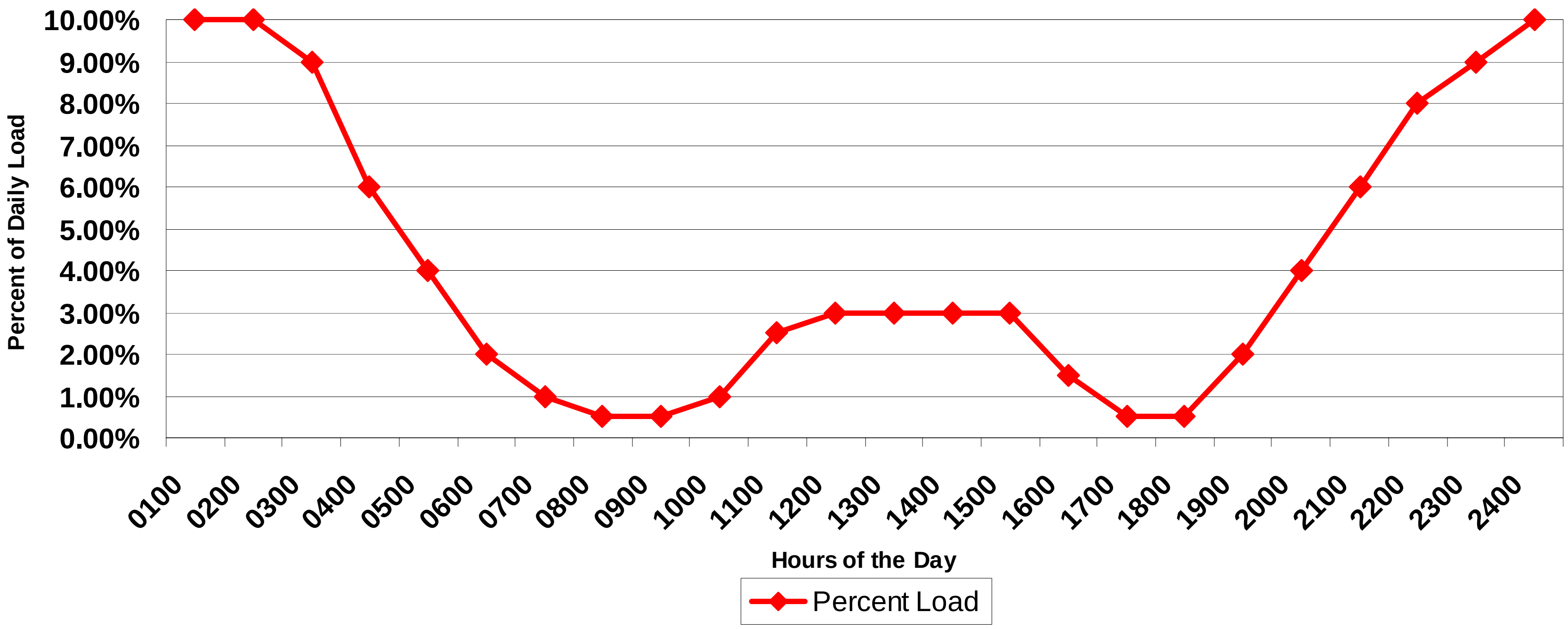
Plug-in Hybrid Electric Vehicles
Uncertainty in Forecast

- California Energy Commission Forecast is approximately 10% of new car sales in 2020 which is at the higher end of independent forecasts.
- Chart courtesy of John Petersen on Seeking Alpha Website.



Plug-in Hybrid Electric Vehicles Charging Profile Assumption

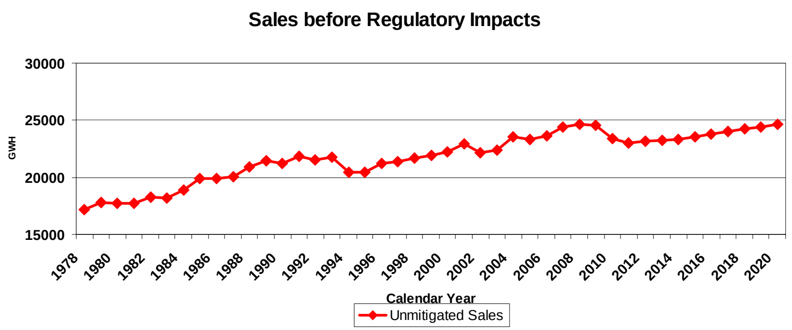
- Based on EPRI research.
- Load Shape potentially could be engineered to optimize LADWP production function.



Plausibility

- Comparing unmitigated 2011 Sales Forecast to historical sales.
  - Unmitigated means forecasting sales based on economics alone before the impacts of environmental programs are considered.
  - Forecasted sales decline from 2008 to 2011 is largest in the past 30 years.
  - Next decade similar to what occurred in the 1990s before additional regulation.

Peak-to-Through Analysis		
Years	GWH Decline	Percent Decline
2008-2011	1,910	8.3%
1992-1994	1,421	7.0%
2000-2002	572	2.6%
1979-1980	322	1.8%
1981-1982	145	0.8%



CITY OF LOS ANGELES

DEPARTMENT

OF

WATER AND POWER

2012 RETAIL ELECTRIC SALES AND DEMAND FORECAST

Ronald O. Nichols
General Manager

Aram Benyamin
Senior Assistant General Manager
Power System

Philip R. Leiber
Chief Financial Officer

March 7, 2012
Load Forecasting, Room 956
Financial Services Organization

Document reflects previous 8.6% energy efficiency goal by 2020.
Forecast will be updated to incorporate revised goal.

Table of Contents

2012 Retail Electric Sales and Demand Forecast

Overview

The 2012 Retail Electric Sales and Demand Forecast (Forecast) supersedes the 2011 Retail Electric Sales and Demand Forecast as the City of Los Angeles Department of Water and Power's (LADWP) official Power System Forecast. The Forecast is the basis for LADWP Power System planning activities including but not limited to Financial Planning, Integrated Resource Planning (IRP), Transmission and Distribution Planning and Wholesale Marketing.

Because the Forecast is a public document, only publically available information is used in its development. (This practice has become a standard among California electric utilities.) LADWP Planners wishing to use their own proprietary data should adjust the Forecast accordingly. The Load Forecast Group (LFG) is available to help Planners make adjustments and produces an Unmitigated and Gross Forecast to facilitate those adjustments.

Data Sources

1. Historical Sales reconciled to the Consumption and Earnings Report prepared by General Accounting.
2. Historical NEL, Peak Demand and Losses reconciled to the PowerMaster database maintained by the Power System Planning & Development Group.
3. Historical weather data is provided by the National Weather Service and Los Angeles Pierce College.
4. Historical Los Angeles County employment data is provided by the State of California Economic Development Division using the March 2010 Benchmark.
5. Historical population estimates and projections are provided by the State of California Department of Finance.
6. The long-term Los Angeles County economic forecast with quarterly short-run updates is provided by UCLA Anderson Forecast.
7. The construction activity forecast is provided by McGraw-Hill Construction.
8. The Electric Vehicle forecast is based on the California Energy Commission (CEC) statewide forecast. The California Electric Transportation Coalition of which LADWP is a member prepared the CEC forecast.
9. The port electrification forecast is provided by the Port of Los Angeles.
10. The LADWP program energy efficiency forecast is based on the LADWP Energy Efficiency projected budget through Fiscal year 2016-17 dated February 21, 2012. Historical installation rates are provided by the Energy Efficiency group.
11. The forecasted impacts of the Energy Independence Security Act (EISA) and the Huffman Bill on residential lighting rely on the Energy Efficiency Potential Study prepared in 2010 by Global Energy.
12. Historical and projected solar rooftop installations are the draft 2011 Integrated Resources Planning Assumptions document dated October 14, 2011.
13. Electric Price Forecast is developed by Financial Services organization.
14. Historical data is current through December 2011.

Five-Year Sales Forecast

The Retail Sales Forecast represents sales that will be realized at the meter through Fiscal Year End 2017. After FYE 2017, some of the forecasted sales will not be realized at the meter due to the incremental impacts of LADWP-sponsored energy efficiency programs. After FYE 2017, LADWP-sponsored energy efficiency programs will be accounted for in the Integrated Resource Plan.

The historical accumulated Energy Efficiency and Solar Saving are from 1999 forward and only include LADWP installed savings. Since July 1, 2008, LADWP-installed Energy Efficiency savings are 715 GWH for which LADWP recovers lost revenue. In the Forecast, energy efficiency and solar savings are expected to occur uniformly throughout the year as a simplifying assumption. Installation schedules are difficult to prepare because they rely on the customers allowing the installation to occur.

Retail sales decrease of 0.6 percent in Fiscal Year 2013-14 is attributed to the full ramp up of the Huffman Bill and accelerated incremental savings rates in LADWP's energy efficiency programs. Beginning January 2012, the Huffman Bill significantly raises the efficiency standard of light bulbs. The 0.5 increase in FYE 2014-15 is due to the projected completion of port electrification projects and a decline in the LADWP incremental energy efficiency savings rate.

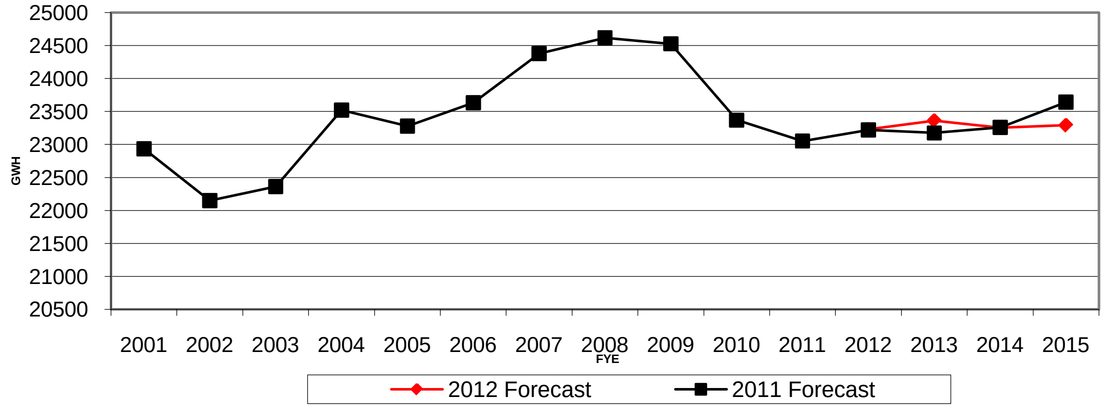
Forecasted Energy Efficiency is based LADWP Board-approved AB 2021 goal of saving 2161 GWH from FYE 2011 through FYE 2020 and forecasted Huffman bill savings. The targeted goal for rooftop solar installations is 242 MW by 2030.

Short-Run Growth

Fiscal Year	Retail Sales		Accumulated EE & Solar Savings	Gross Sales
Ending June 30	(GWH)	YOY Growth Rate	(GWH)	(GWH)
2010-11	23053		1470	24523
Forecast				
2011-12	23232	0.8%	1725	24957
2012-13	23364	-0.4%	2062	25426
2013-14	23256	-0.6%	2428	25684
2014-15	23294	0.2%	2772	26066
2015-16	23253	-0.1%	3113	26366
2016-17	23224	-0.1%	3448	26672

[1] Actual sales through December 2011

Retail Sales Net of Energy Efficiency and Distributed Generation



Peak Demand Forecast

Growth in annual peak demand over the next ten years is 0.3 percent.

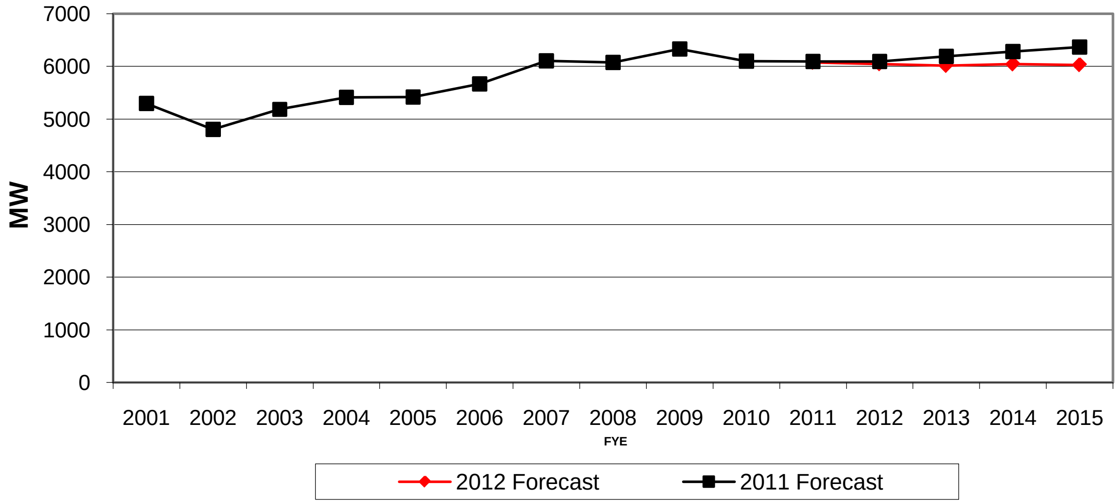
Long-Run Growth

Fiscal Year End June 30	Base Case Peak Demand (MW)	Growth Rate Base Year 2011-12	One-in-Ten Peak Demand (MW)
2011-12	5631[1]		6073
Forecast			
2016-17	5590	-0.1%	6026
2021-22	5881	0.4%	6342
2031-32	6441	0.7%	6885
2040-41	6992	0.7%	7546

[1]Weather-normalized. Actual peak was 5907 MW.

In 2011, the System set its calendar annual peak at 5907 MW on September 7, 2011 on a day that was a 1-in-2.3 weather event. The weather-adjusted one-in-two peak for 2011 is 5631 MW. The following graph of the One-in-Ten peak demand forecast is used for the Integrated Resource Plan (IRP). In the 1990s through 2005, annual System load factors were trending slowly upward. Since 2006, System load factors are trending down. Three factors are generally thought to be contributing to this effect. Most customers are making greater efforts to conserve energy but during extreme weather events safety and comfort predominate over conservation causing the peak to spike. Much of the historical and forecasted energy efficiency effort is lighting which has a greater impact on consumption rather than peak which lowers the load factor. Solar rooftops peak production is between 1200 and 1300 hours and declines to 40 to 50 percent of capacity at 1600 hours when the peak occurs. In contrast, the load factor will rise due to significant load growth from the greater use of electric vehicles. The new electric vehicle forecast adopted from the California Electric Transportation Coalition has less impact on the peak than the 2011 Forecast.

One-in-Ten Peak Demand Comparisons



The Peak Demand Forecast is primarily used in the following areas:

1. Integrated Resource Planning
2. Wholesale Energy Marketing
3. Distribution Planning
4. Transmission Planning

In Integrated Resource Planning, LADWP uses the One-in-Ten Case Peak Demand forecast rather than the Base Case forecast. LADWP's policy is to ensure reliability in times of volatility by controlling its own generation capacity. Planning generation resources at the one-in-ten level has proven over the years to be an effective tool in meeting the reliability policy. The one-in-ten case is based on historical peak day weather events and uses a statistical model and the underlying retail sales forecast to forecast an annual peak demand. The peak demand is adjusted for lighting energy efficiency and electric vehicle impacts.

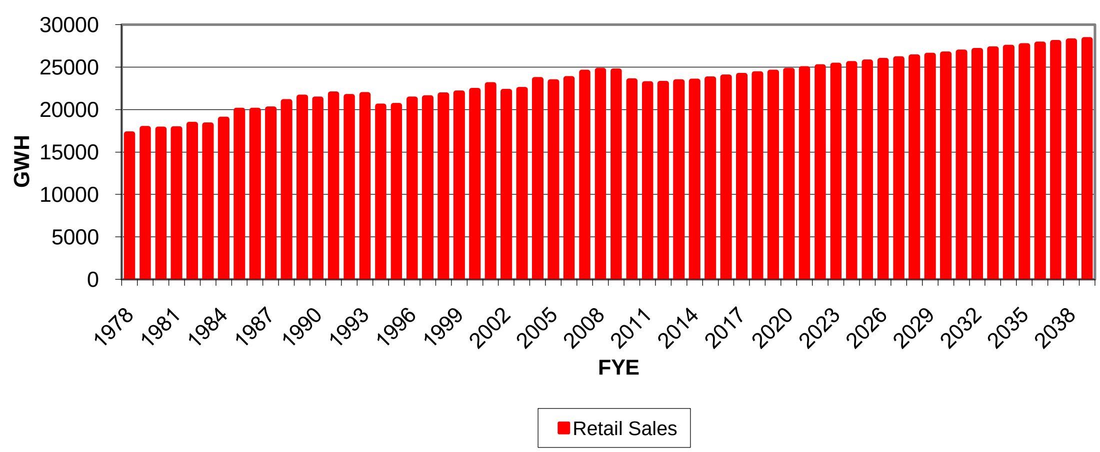
Plausibility

To measure plausibility we compare the current forecast to historical periods. Data is available electronically from 1978 forward. A direct comparison is not appropriate because the forecast period includes programs that reduce all forms of energy consumption due to an aggressive regulatory agenda primary aimed at reducing greenhouse emissions. Instead the unmitigated forecast is compared against history. The unmitigated forecast is the forecast that would occur before the impacts of AB 32 and AB 2021 are considered. It might also be considered a "business-as-usual" case.

The decline in forecasted sales 2008 through 2010 is most directly compared to the decline in sales between 1992 and 1994. The 1992 through 1994 time period was difficult for Los Angeles in many aspects. An economic slump occurred mostly created by the downsizing of the aerospace industry but it also was time of civil unrest and natural disaster. The combination of events caused a major migration of people leaving Los Angeles. Peak-to-Trough sales declined 7 percent in the 1992 through 1994 time period. The following table shows all the peak-to-through declines since 1978. The chart then gives visual evidence of the long-term perspective.

Peak-to-Trough Analysis		
Years	GWH Decline	Percent Decline
2008-2010	1,910	8.3%
1992-1994	1,421	7.0%
2000-2002	572	2.6%
1979-1980	322	1.8%
1981-1982	145	0.8%

Retail Sales before Regulatory Impacts



Primarily due to the recession that began in December 2007 and ended in June 2009, the historical sales experienced a decline of 8.3 percent in the 2008 through 2010 time period. While the 1992-94 sales decline was specific to Los Angeles and the aerospace industry, in 2008-2010 the decline in Los Angeles mirrored the malaise in the national economy. Going forward, there are conflicting trends in the economic forecast for Los Angeles County going forward. On the positive note, Real Personal Income is increasing. Per capita energy consumption is historically positively correlated with increases in personal income and consumption. The negative trends are population out-migration and fewer jobs in Los Angeles County. Population out-migration means smaller demand for housing infrastructure. Fewer jobs imply that vacant commercial floor space will not be absorbed. Based on economic variables sales will not reach 2008 levels until 2021. The next decade will be much like the 1990s.

Variables in the Forecast

Population: The 2010 United States Census reported 3,792,621 residents in the City of Los Angeles. This number was far lower than the previous 4,094,764 estimated by State of California Department of Finance Demographic unit. The State relies on birth-death records and driver license data to estimate population between censuses. The 2000 United States Census reported 3,694,742. The population growth rate was only 0.2 percent per annum in the first decade of the 21st century. This data seems contrary to other data such as new residential accounts for example. New residential accounts increased at a 0.5% rate in the same time period. This Forecast relies less on the population data since it gives us an unexpected result.

SB 375: SB 375 layers statewide guidelines onto local planning decisions. It favors redevelopment, known as brown field development, near transportation centers over new (green field) development. The goal is to reduce vehicle miles traveled thereby reducing emissions. Most development in Los Angeles is brown field development. However, brown field development is more complicated and expensive than green field development so overall development could slow. The City of LA's "Housing that Works" plan fits well into the SB 375 structure. Residential construction activity is forecast to rebound to normal levels within the next three years.

Emission Allowances: AB 32 seeks to reduce emissions to 1990 levels using a cap-and – trade scheme. Originally the program was to begin in 2012 but has been delayed. Program is designed to protect utilities and consumers. Ultimate impacts are unknown.

Electric Vehicles: LADWP is making electric vehicles a key strategic initiative. The Forecast uses the 2011 California Energy Commission mid-level forecast for electric load growth. This forecast was developed by the California Plug-in Electric Vehicle Coalition of which LADWP is a member. Demand response strategies are intrinsic to this forecast whereas in the 2011 Forecast Demand Response strategies for electric vehicles were external to the electric vehicle forecast. Alternative forecasts for load growth from electric vehicles vary widely.

Energy Efficiency: According to the State of California Strategic Plan, achieving the energy efficiency goals relies on new emerging technologies. The timing of the market availability and the adoption rates for the new technologies is unknown.

Smart Grid: It is unknown when LADWP will complete its Smart Grid program. Some believe that developing a Smart Grid system is a necessary precondition towards a successful electric vehicle program. Also Smart Grid is an important component towards achieving energy efficiency goals in the residential sector.

Vacancy Factor in Residential Sector: Vacancy rose faster than expected in the recession. Some of the vacancy rate was due to households combining and living in the same structure. Vacancy could rapidly swing lower as the economy begins to expand. The Forecast has vacancy rate returning to five percent which is the long-term average by 2015.

Vacancy Factor in Commercial Sector: High vacancy factor is expected to remain more persistent in the commercial sector as models for delivery of services especially in retail change. The rise of big-box retail stores and the Internet have crowded out the small retail shop owner over the past twenty years. There is a smaller need for a physical presence.

Panama Canal Widening: Panama is widening its canal to accommodate the modern larger container ships.   It is expected to be completed by 2014. Eastern seaports are also dredging to allow the larger container ships to dock.   Currently the larger container ships dock in Los Angeles and Long Beach and the goods are shipped by rail to the East Coast. A decline in this business would hurt the Los Angeles economy. Wholesale Trade and Transportation represent about ten percent of the employment in Los Angeles County.

2012 RETAIL ENERGY AND DEMAND FORECAST

NET ELECTRICITY SALES BY CUSTOMER CLASS AND SYSTEM PEAK DEMAND WITH REGULATORY IMPACTS

	SECTOR SALES					Total Sales to Ultimate	LOSSES		Net Energy		Service	Peak		Service	
Fiscal Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Miscellaneous* (GWh)	Electric Vehicles (GWh)	Customers (GWh)	Total (GWh)	DC Line (GWh)	for Load (GWh)	Cogen (GWh)	Area Load (GWh)	Demand (MW)	Cogen (MW)	Area Peak (MW)	
2000-01	7,542	12,107	2,754	531	0	22,934	2,753	407	25,688	1,294	26,981	5,299	184	5,483	
2001-02	7,282	11,843	2,496	528	0	22,149	2,755	350	24,903	1,059	25,962	4,805	181	4,986	
2002-03	7,358	12,077	2,383	545	0	22,363	3,006	444	25,370	1,069	26,438	5,185	184	5,369	
2003-04	8,061	12,408	2,485	565	0	23,520	3,181	239	26,701	1,073	27,774	5,410	186	5,596	
2004-05	7,907	12,374	2,447	551	0	23,279	3,059	216	26,338	1,075	27,413	5,418	187	5,605	
2005-06	8,051	12,580	2,451	551	0	23,634	3,194	482	26,828	1,076	27,903	5,667	188	5,855	
2006-07	8,495	12,984	2,332	567	0	24,378	3,125	377	27,502	1,077	28,579	6,102	191	6,293	
2007-08	8,540	13,134	2,366	576	0	24,617	3,311	425	27,928	1,080	29,007	6,071	193	6,264	
2008-09	8,578	13,084	2,303	560	0	24,526	2,921	350	27,447	1,084	28,531	5,647	196	5,843	1
2009-10	8,300	12,463	2,073	532	0	23,369	3,157	262	26,526	1,092	27,617	5,709	203	5,912	
2010-11	8,068	12,333	2,189	464	0	23,053	3,200	598	26,252	1,105	27,357	6,142	212	6,354	
2011-12	8,353	12,474	1,932	473	1	23,232	3,226	411	26,458	1,116	27,574	5,907	224	6,131	
2012-13	8,407	12,513	1,947	493	4	23,364	2,996	411	26,360	1,184	27,544	5,606	232	5,837	
2013-14	8,290	12,545	1,927	485	8	23,256	3,054	411	26,310	1,208	27,518	5,577	238	5,815	
2014-15	8,279	12,588	1,936	479	12	23,294	3,017	411	26,311	1,227	27,538	5,604	243	5,847	
2015-16	8,257	12,557	1,937	480	22	23,253	3,058	411	26,312	1,248	27,560	5,591	248	5,840	
2016-17	8,239	12,532	1,938	482	34	23,224	3,011	411	26,235	1,263	27,498	5,590	252	5,842	
2017-18	8,288	12,607	1,938	484	61	23,378	3,014	411	26,392	1,271	27,663	5,597	254	5,851	
2018-19	8,381	12,764	1,939	486	97	23,667	3,038	411	26,705	1,280	27,985	5,658	256	5,914	
2019-20	8,474	12,920	1,940	488	151	23,973	3,143	411	27,115	1,290	28,405	5,725	258	5,983	
2020-21	8,555	13,122	1,940	490	223	24,330	3,122	411	27,451	1,301	28,752	5,791	261	6,052	
2021-22	8,638	13,312	1,941	492	328	24,711	3,167	411	27,878	1,312	29,190	5,881	264	6,145	
2022-23	8,718	13,442	1,941	494	402	24,997	3,202	411	28,199	1,315	29,514	5,942	267	6,209	
2023-24	8,805	13,572	1,942	496	416	25,230	3,307	411	28,537	1,338	29,875	5,995	270	6,265	
2024-25	8,896	13,702	1,942	498	429	25,467	3,271	411	28,739	1,352	30,091	6,050	274	6,324	
2025-26	8,985	13,831	1,943	500	452	25,710	3,300	411	29,010	1,367	30,377	6,105	277	6,383	
2026-27	9,076	13,960	1,943	502	467	25,948	3,334	411	29,283	1,382	30,665	6,160	281	6,441	
2027-28	9,168	14,089	1,944	503	489	26,193	3,432	411	29,626	1,397	31,023	6,216	284	6,500	
2028-29	9,260	14,217	1,945	505	505	26,431	3,396	411	29,828	1,414	31,242	6,271	288	6,559	
2029-30	9,351	14,344	1,945	507	526	26,673	3,427	411	30,101	1,430	31,531	6,326	292	6,618	
2030-31	9,447	14,480	1,946	509	542	26,925	3,460	411	30,385	1,430	31,815	6,381	292	6,674	
2031-32	9,545	14,623	1,946	511	562	27,188	3,562	411	30,749	1,430	32,179	6,441	292	6,733	
2032-33	9,643	14,765	1,947	513	580	27,448	3,527	411	30,975	1,430	32,405	6,515	292	6,807	
2033-34	9,741	14,907	1,947	515	599	27,710	3,560	411	31,271	1,430	32,701	6,560	292	6,852	
2034-35	9,840	15,048	1,948	517	617	27,971	3,595	411	31,566	1,430	32,996	6,619	292	6,912	
2035-36	9,940	15,189	1,949	519	636	28,233	3,698	411	31,931	1,430	33,361	6,679	292	6,971	
2036-37	10,039	15,329	1,949	521	654	28,493	3,663	411	32,156	1,430	33,586	6,753	292	7,046	
2037-38	10,139	15,470	1,950	523	674	28,756	3,696	411	32,452	1,430	33,882	6,798	292	7,090	
2038-39	10,240	15,610	1,950	525	692	29,017	3,731	411	32,748	1,430	34,178	6,858	292	7,150	
2039-40	10,341	15,751	1,951	527	711	29,280	3,834	411	33,114	1,430	34,544	6,917	292	7,210	

[1] Table updated through December 2012

Electric Vehicle Sales before January 2012 included in Residential and Commercial Sales

Annual Percent Change

	Residential	Commercial	Industrial	Miscellaneous*	Electric Vehicles	Total Sales	Losses Total	DC Line	Net Energy for Load	Cogen (GWh)	Service Area Load	Peak Demand	Cogen (MW)	Service Area Peak
1991-2001	1.03%	0.55%	-1.02%	0.53%		0.50%			0.48%		0.57%	-0.02%		0.10%
2001-11	0.68%	0.18%	-2.27%	-1.34%		0.05%			0.22%		0.14%	1.49%		1.49%
2011-17	0.35%	0.27%	-2.01%	0.65%		0.12%			-0.01%		0.09%	-1.56%		-1.39%
2011-21	0.59%	0.62%	-1.20%	0.55%		0.54%			0.45%		0.50%	-0.59%		-0.48%
2011-31	0.79%	0.81%	-0.59%	0.47%		0.78%			0.73%		0.76%	0.19%		0.25%
2011-40	0.86%	0.85%	-0.40%	0.44%		0.83%			0.80%		0.81%	0.41%		0.44%

*****'Miscellaneous' includes Streetlighting, Owens Valley, and Intra-Departmental.

PEAK DEMAND - MW
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	MAXIMUM
2001-02	4799	4805	4681	4604	3694	3626	3632	3576	3421	3599	4177	4493	4805
2002-03	4910	4874	5185	4463	4039	3735	3878	3724	3932	3860	4782	4522	5185
2003-04	5337	5410	5273	4159	3825	3887	3632	3606	4080	5161	5316	4448	5410
2004-05	5402	5123	5418	4087	3701	3956	3848	3698	3583	3815	4629	4524	5418
2005-06	5667	5405	5093	4692	4040	3732	3709	3702	3677	3592	4587	5498	5667
2006-07	6102	5305	5656	4529	4406	3965	4023	3694	4214	4059	4840	4729	6102
2007-08	5341	6071	5917	4557	4052	3908	3908	3778	3868	4769	5303	6006	6071
2008-09	5128	5384	5472	5647	3997	4176	3707	3672	3706	5064	4761	4304	5647
2009-10	5569	5553	5709	4510	3794	3918	3925	3756	3597	3523	3818	4322	5709
2010-11	5511	5592	6142	4900	4457	3786	3766	3628	4114	4246	4518	4387	6142

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	MAXIMUM
2011-12	5340	5348	5907	5039	3591	3887	3849	3825	3822	4129	4451	4714	5907
2012-13	5301	5606	5303	4519	3984	3954	3823	3797	3797	4111	4431	4692	5606
2013-14	5266	5577	5278	4499	3958	3928	3836	3810	3810	4135	4456	4718	5577
2014-15	5284	5604	5305	4524	3971	3941	3822	3796	3796	4131	4450	4712	5604
2015-16	5265	5591	5297	4518	3957	3927	3816	3794	3790	4135	4453	4715	5591
2016-17	5256	5590	5299	4521	3951	3920	3821	3795	3795	4144	4463	4725	5590
2017-18	5263	5597	5310	4531	3956	3925	3863	3837	3837	4195	4517	4782	5597
2018-19	5322	5658	5373	4586	4000	3969	3912	3886	3886	4252	4578	4846	5658
2019-20	5389	5725	5445	4648	4050	4019	3962	3934	3935	4310	4641	4913	5725
2020-21	5458	5791	5519	4712	4102	4071	4032	4004	4004	4390	4726	5002	5791
2021-22	5553	5881	5619	4798	4174	4142	4086	4058	4058	4450	4791	5071	5881
2022-23	5628	5942	5696	4864	4230	4198	4124	4096	4096	4493	4837	5120	5942
2023-24	5681	5995	5751	4911	4270	4237	4164	4127	4135	4537	4885	5170	5995
2024-25	5735	6050	5808	4959	4311	4278	4203	4175	4175	4582	4933	5221	6050
2025-26	5790	6105	5864	5007	4352	4318	4243	4214	4214	4626	4980	5271	6105
2026-27	5844	6160	5920	5056	4392	4359	4283	4254	4253	4671	5028	5322	6160
2027-28	5899	6216	5977	5104	4434	4400	4322	4279	4293	4715	5076	5372	6216
2028-29	5954	6271	6034	5153	4475	4441	4362	4332	4332	4759	5124	5422	6271
2029-30	6008	6326	6090	5201	4516	4481	4402	4372	4372	4804	5172	5473	6326
2030-31	6063	6381	6147	5250	4557	4522	4445	4415	4414	4852	5223	5527	6381
2031-32	6122	6441	6207	5302	4601	4566	4488	4438	4457	4899	5274	5581	6441
3032-33	6181	6515	6268	5354	4646	4610	4531	4500	4500	4947	5325	5635	6515
2033-34	6241	6560	6329	5406	4690	4655	4574	4543	4542	4995	5376	5690	6560
2034-35	6300	6619	6390	5458	4735	4699	4617	4585	4585	5042	5428	5744	6619
2035-36	6359	6679	6450	5510	4779	4743	4660	4603	4628	5090	5479	5798	6679
2036-37	6418	6753	6511	5561	4824	4787	4703	4671	4670	5137	5530	5852	6753
2037-38	6478	6798	6572	5613	4868	4831	4746	4714	4713	5185	5581	5906	6798
2038-39	6537	6858	6633	5666	4913	4876	4789	4756	4756	5233	5633	5960	6858
2039-40	6596	6917	6693	5718	4958	4920	4832	4768	4799	5280	5684	6015	6917

[1]Weather Normalized for Fiscal Year 2011-12 is 5631 MW.

MINIMUM DEMAND - MW
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	AVERAGE
2001-02	1933	1944	1985	1927	1879	1988	2010	1936	1881	1932	1879	1942	1936
2002-03	2009	1986	2015	1940	1917	1984	1996	1996	1913	1858	1892	1996	1959
2003-04	2140	2187	2163	1808	1982	2030	2107	2103	1931	1926	1912	2095	2032
2004-05	2071	2171	2161	2061	2057	2108	1984	2083	1982	1944	1925	2035	2049
2005-06	2100	2187	2043	2083	2085	2128	2109	2074	2114	2041	2068	2122	2096
2006-07	2406	2246	2196	2093	2088	2242	2276	2170	2080	2036	2050	2152	2170
2007-08	2287	2289	2173	2146	2106	2114	2229	2190	2121	2125	2078	2192	2171
2008-09	2262	2347	2229	2182	2091	2155	2131	2135	2117	2022	2062	1997	2144
2009-10	2041	2172	2155	2049	2050	2170	2142	2107	2047	2015	2000	2066	2085
2010-11	2084	1925	1981	2029	2045	2091	2126	2151	2094	2061	2031	2055	2056

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	AVERAGE
2011-12	2114	2207	2134	2056	2062	2144	2082	2180	2010	2001	2042	2046	2090
2012-13	2074	2096	2104	2072	2080	2132	2068	2089	1996	1988	2029	2032	2063
2013-14	2060	2082	2090	2058	2066	2118	2075	2096	2003	1994	2036	2039	2060
2014-15	2067	2089	2097	2065	2073	2125	2067	2089	1996	1987	2028	2032	2060
2015-16	2059	2081	2089	2058	2066	2118	2064	2162	1993	1984	2025	2028	2061
2016-17	2056	2078	2086	2054	2063	2114	2067	2088	1995	1986	2028	2031	2054
2017-18	2059	2081	2089	2057	2065	2117	2090	2112	2017	2009	2050	2054	2066
2018-19	2082	2104	2112	2080	2088	2140	2116	2138	2043	2034	2076	2080	2091
2019-20	2108	2131	2138	2106	2115	2168	2143	2242	2069	2060	2103	2106	2124
2020-21	2135	2158	2166	2133	2142	2195	2181	2203	2105	2096	2139	2143	2150
2021-22	2172	2195	2204	2170	2179	2234	2210	2233	2133	2124	2168	2172	2183
2022-23	2202	2225	2233	2200	2208	2264	2231	2254	2154	2144	2189	2192	2208
2023-24	2222	2246	2254	2220	2229	2285	2252	2352	2174	2165	2210	2213	2235
2024-25	2244	2267	2276	2242	2251	2307	2274	2297	2195	2185	2231	2234	2250
2025-26	2265	2289	2298	2263	2272	2329	2295	2319	2215	2206	2251	2255	2271
2026-27	2286	2310	2319	2284	2293	2351	2316	2341	2236	2227	2273	2276	2293
2027-28	2308	2332	2341	2306	2315	2373	2338	2439	2257	2247	2294	2298	2321
2028-29	2329	2354	2363	2327	2336	2395	2359	2384	2278	2268	2315	2319	2335
2029-30	2350	2375	2384	2348	2358	2417	2381	2406	2299	2289	2336	2340	2357
2030-31	2372	2397	2406	2370	2379	2439	2404	2429	2321	2311	2359	2363	2379
2031-32	2395	2420	2429	2393	2402	2462	2427	2529	2343	2333	2381	2385	2408
3032-33	2418	2444	2453	2416	2426	2486	2451	2476	2366	2355	2404	2408	2425
2033-34	2441	2467	2476	2439	2449	2510	2474	2500	2388	2378	2427	2431	2448
2034-35	2464	2491	2500	2462	2472	2534	2497	2523	2411	2400	2450	2454	2472
2035-36	2488	2514	2523	2485	2495	2558	2520	2623	2433	2422	2473	2477	2501
2036-37	2511	2537	2547	2509	2519	2582	2544	2570	2456	2445	2495	2500	2518
2037-38	2534	2561	2570	2532	2542	2605	2567	2594	2478	2467	2518	2523	2541
2038-39	2557	2584	2594	2555	2565	2629	2590	2617	2501	2490	2541	2545	2564
2039-40	2580	2608	2618	2578	2588	2653	2613	2717	2523	2512	2564	2568	2594

NET ENERGY FOR LOAD- GWH
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	2206	2338	2138	2109	1965	2044	2100	1830	1972	1966	2068	2168	24903
2002-03	2391	2324	2306	2096	2005	2076	2077	1854	2069	1957	2104	2111	25370
2003-04	2581	2621	2352	2262	1983	2139	2119	1964	2136	2069	2253	2221	26701
2004-05	2460	2444	2440	2175	2051	2187	2166	1912	2101	2020	2209	2172	26338
2005-06	2582	2572	2232	2221	2076	2154	2141	1927	2143	2015	2238	2527	26828
2006-07	2935	2589	2398	2187	2142	2227	2178	1972	2200	2091	2267	2318	27502
2007-08	2664	2760	2420	2267	2119	2222	2251	2079	2144	2132	2288	2580	27928
2008-09	2701	2703	2528	2406	2115	2240	2187	1962	2131	2069	2253	2152	27447
2009-10	2597	2523	2542	2176	2030	2201	2151	1917	2087	1985	2078	2239	26526
2010-11	2373	2424	2311	2171	2069	2165	2193	1953	2185	2068	2157	2183	26252

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2011-12	2514	2570	2333	2201	2038	2164	2140	1997	2105	2036	2169	2190	26458
2012-13	2507	2563	2348	2231	2065	2161	2126	1915	2091	2022	2155	2175	26360
2013-14	2491	2546	2333	2216	2052	2147	2133	1921	2098	2029	2162	2183	26310
2014-15	2499	2554	2341	2223	2059	2154	2126	1914	2091	2022	2154	2175	26311
2015-16	2490	2545	2332	2215	2051	2146	2122	1981	2087	2019	2151	2171	26312
2016-17	2486	2541	2328	2212	2048	2143	2125	1914	2090	2021	2154	2174	26235
2017-18	2489	2544	2331	2215	2051	2146	2149	1935	2113	2044	2178	2198	26392
2018-19	2517	2573	2357	2239	2073	2170	2176	1959	2140	2070	2205	2226	26705
2019-20	2549	2605	2387	2268	2100	2197	2204	2055	2167	2096	2233	2254	27115
2020-21	2581	2639	2418	2297	2126	2225	2242	2019	2205	2133	2272	2294	27451
2021-22	2626	2685	2460	2337	2164	2264	2272	2046	2235	2161	2303	2325	27878
2022-23	2662	2721	2493	2368	2193	2295	2294	2066	2256	2182	2325	2347	28199
2023-24	2687	2746	2516	2390	2213	2316	2316	2155	2277	2203	2347	2369	28537
2024-25	2713	2773	2541	2413	2235	2338	2338	2105	2299	2223	2369	2392	28739
2025-26	2738	2799	2565	2436	2256	2361	2360	2125	2321	2244	2392	2414	29010
2026-27	2764	2825	2589	2459	2277	2383	2382	2145	2342	2265	2414	2437	29283
2027-28	2790	2852	2613	2482	2298	2405	2404	2235	2364	2286	2436	2459	29626
2028-29	2816	2878	2637	2505	2320	2427	2426	2185	2386	2307	2459	2482	29828
2029-30	2842	2905	2661	2528	2341	2449	2448	2205	2408	2328	2481	2505	30101
2030-31	2868	2931	2686	2551	2362	2472	2472	2226	2431	2351	2505	2529	30385
2031-32	2896	2960	2712	2576	2385	2496	2496	2318	2455	2374	2530	2553	30749
3032-33	2924	2988	2738	2601	2408	2520	2520	2269	2478	2397	2554	2578	30975
2033-34	2952	3017	2764	2626	2431	2544	2544	2291	2502	2419	2578	2602	31271
2034-35	2980	3046	2791	2651	2455	2568	2568	2312	2525	2442	2602	2627	31566
2035-36	3008	3074	2817	2676	2478	2593	2591	2404	2549	2465	2626	2651	31931
2036-37	3036	3103	2843	2701	2501	2617	2615	2355	2572	2488	2651	2676	32156
2037-38	3064	3131	2869	2726	2524	2641	2639	2377	2596	2510	2675	2700	32452
2038-39	3092	3160	2896	2751	2547	2665	2663	2398	2619	2533	2699	2725	32748
2039-40	3120	3189	2922	2776	2570	2689	2687	2490	2643	2556	2723	2749	33114

TOTAL SALES TO ULTIMATE CUSTOMERS- GWH
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	1971	1948	2055	1903	1845	1794	1827	1798	1738	1724	1657	1888	22149
2002-03	1977	1932	1977	2037	1819	1918	1849	1872	1678	1755	1691	1860	22363
2003-04	1948	2164	2200	2110	2027	1891	2006	1810	1735	1852	1843	1933	23520
2004-05	1991	2120	2116	2070	1895	1977	1969	1852	1778	1798	1756	1956	23279
2005-06	1998	2176	2151	2055	1874	2038	1985	1863	1831	1828	1781	2053	23634
2006-07	2234	2390	2304	2137	1953	1959	1983	1932	1852	1853	1850	1932	24378
2007-08	2147	2253	2365	2187	1986	1979	2005	2015	1896	1899	1855	2031	24617
2008-09	2383	2143	2300	2270	2079	1964	2007	2002	1799	1819	1836	1926	24526
2009-10	1982	2127	2253	2289	1867	1881	1947	1925	1759	1745	1711	1883	23369
2010-11	1943	1987	2068	2110	1891	1960	1957	1941	1789	1826	1779	1802	23053

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2011-12	1980	2042	2175	2074	1883	1894	1990	1898	1816	1785	1799	1897	23232
2012-13	2037	2125	2177	2065	1934	1913	1973	1889	1806	1773	1787	1885	23364
2013-14	2023	2112	2165	2052	1919	1896	1969	1886	1802	1769	1783	1881	23256
2014-15	2046	2144	2186	2074	1922	1897	1960	1876	1789	1756	1770	1876	23294
2015-16	2041	2141	2184	2072	1918	1893	1958	1874	1786	1752	1765	1870	23253
2016-17	2037	2139	2182	2069	1915	1890	1957	1873	1784	1749	1762	1867	23224
2017-18	2037	2143	2190	2078	1925	1901	1972	1890	1801	1768	1782	1891	23378
2018-19	2062	2170	2216	2103	1947	1924	1996	1914	1825	1790	1805	1915	23667
2019-20	2088	2197	2244	2130	1971	1948	2021	1940	1850	1815	1829	1940	23973
2020-21	2114	2225	2271	2156	1995	1972	2055	1975	1883	1848	1862	1974	24330
2021-22	2150	2263	2309	2192	2030	2006	2082	2002	1912	1874	1889	2002	24711
2022-23	2180	2294	2339	2221	2055	2029	2105	2024	1931	1893	1907	2020	24997
2023-24	2199	2314	2359	2239	2072	2048	2125	2045	1951	1912	1926	2040	25230
2024-25	2219	2337	2381	2260	2091	2067	2145	2065	1970	1930	1944	2059	25467
2025-26	2240	2359	2403	2281	2110	2086	2166	2086	1990	1949	1963	2079	25710
2026-27	2261	2381	2425	2301	2129	2105	2186	2106	2009	1967	1981	2098	25948
2027-28	2282	2404	2447	2322	2148	2124	2207	2127	2029	1986	2000	2118	26193
2028-29	2303	2426	2469	2343	2167	2143	2226	2147	2048	2004	2018	2137	26431
2029-30	2323	2449	2492	2364	2186	2162	2247	2167	2068	2023	2036	2156	26673
2030-31	2344	2471	2514	2385	2205	2182	2268	2189	2088	2043	2057	2177	26925
2031-32	2367	2496	2538	2408	2226	2202	2290	2211	2110	2064	2077	2199	27188
3032-33	2390	2520	2562	2431	2246	2222	2311	2233	2131	2084	2097	2220	27448
2033-34	2413	2545	2586	2453	2267	2243	2333	2255	2152	2105	2118	2241	27710
2034-35	2435	2569	2610	2476	2287	2263	2355	2277	2174	2125	2138	2262	27971
2035-36	2458	2593	2634	2498	2307	2283	2376	2299	2195	2146	2159	2284	28233
2036-37	2481	2618	2658	2521	2328	2304	2398	2321	2216	2166	2179	2305	28493
2037-38	2504	2642	2682	2543	2348	2324	2420	2343	2238	2187	2199	2326	28756
2038-39	2527	2667	2706	2566	2368	2344	2442	2365	2259	2207	2220	2347	29017
2039-40	2549	2691	2731	2588	2389	2365	2463	2387	2280	2228	2240	2369	29280

RESIDENTIAL SALES - GWH
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	608	659	640	661	582	622	653	654	568	559	520	557	7282
2002-03	600	673	670	678	595	618	652	647	560	560	530	576	7358
2003-04	639	773	787	746	641	682	701	688	596	595	578	635	8061
2004-05	630	726	745	731	620	680	724	687	600	606	552	606	7907
2005-06	640	772	771	712	610	659	701	685	625	649	583	644	8051
2006-07	774	919	838	750	629	669	724	733	631	624	576	628	8495
2007-08	694	812	838	799	646	694	734	761	664	634	593	670	8540
2008-09	758	859	815	816	692	706	731	735	636	616	581	634	8578
2009-10	665	793	820	819	675	696	712	725	629	598	560	607	8300
2010-11	635	710	720	765	659	697	720	719	631	631	581	600	8068

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2011-12	647	753	806	760	651	698	764	740	673	629	606	626	8353
2012-13	701	782	817	758	680	682	750	734	666	621	597	618	8407
2013-14	693	774	809	749	669	669	738	725	657	611	588	610	8290
2014-15	696	784	806	756	667	665	736	723	652	605	582	607	8279
2015-16	694	783	806	755	664	662	735	722	651	603	579	604	8257
2016-17	692	783	805	753	661	659	734	722	650	601	577	602	8239
2017-18	691	785	808	756	664	663	739	728	656	607	583	608	8288
2018-19	699	794	817	765	670	670	748	737	664	614	589	615	8381
2019-20	706	803	827	773	677	677	756	746	672	620	595	621	8474
2020-21	713	812	835	781	683	682	764	754	679	626	601	627	8555
2021-22	720	820	844	788	689	688	771	762	686	632	606	632	8638
2022-23	726	828	852	795	695	694	778	769	693	639	612	638	8718
2023-24	733	836	860	803	701	701	786	778	700	645	618	644	8805
2024-25	740	845	869	811	708	708	795	787	708	652	624	650	8896
2025-26	747	853	877	818	714	714	803	795	716	659	631	656	8985
2026-27	754	862	886	826	721	721	812	804	724	666	637	663	9076
2027-28	762	871	895	834	727	728	820	813	732	673	643	669	9168
2028-29	769	880	904	842	734	735	829	821	740	680	650	675	9260
2029-30	776	888	913	850	741	742	837	830	748	687	656	682	9351
2030-31	783	897	922	859	748	750	846	839	756	694	663	689	9447
2031-32	791	907	932	867	755	757	855	849	765	702	670	695	9545
3032-33	799	916	942	876	762	765	864	858	773	709	677	702	9643
2033-34	807	926	951	884	769	772	873	867	782	717	684	709	9741
2034-35	815	935	961	893	776	779	882	877	791	725	691	716	9840
2035-36	823	945	971	902	784	787	891	886	799	732	698	723	9940
2036-37	831	954	980	911	791	794	900	896	808	740	705	730	10039
2037-38	839	964	990	919	798	802	909	905	817	748	712	737	10139
2038-39	847	973	1000	928	805	810	918	915	825	756	719	744	10240
2039-40	855	983	1010	937	813	817	928	925	834	763	726	751	10341

COMMERCIAL SALES - GWH
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	1086	1025	1147	975	1020	952	916	887	936	931	902	1067	11843
2002-03	1141	983	1050	1091	989	1065	951	969	885	959	958	1036	12077
2003-04	1023	1140	1154	1101	1084	969	1073	862	943	979	1017	1064	12408
2004-05	1084	1124	1129	1099	989	1046	1013	934	956	954	964	1082	12374
2005-06	1097	1151	1121	1115	1019	1081	1027	958	959	952	984	1116	12580
2006-07	1201	1216	1181	1134	1093	1085	1009	968	999	997	1039	1063	12984
2007-08	1169	1171	1254	1130	1090	1062	1051	1022	1002	1023	1048	1111	13134
2008-09	1369	1035	1225	1200	1144	1055	1031	1033	950	958	1025	1061	13084
2009-10	1097	1066	1190	1240	980	1007	1016	983	924	957	964	1039	12463
2010-11	1083	1061	1125	1118	1024	1010	1017	992	938	959	1003	1004	12333

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2011-12	1121	1091	1145	1112	1037	1008	1023	962	952	964	995	1064	12474
2012-13	1119	1122	1140	1097	1052	1029	1023	961	951	963	993	1062	12513
2013-14	1116	1118	1137	1095	1051	1028	1032	970	959	970	1001	1069	12545
2014-15	1137	1141	1160	1110	1055	1032	1024	961	950	962	992	1065	12588
2015-16	1133	1137	1158	1107	1053	1030	1022	959	947	959	989	1062	12557
2016-17	1130	1135	1156	1106	1051	1028	1021	957	945	957	987	1059	12532
2017-18	1129	1135	1158	1109	1056	1034	1028	964	954	967	999	1073	12607
2018-19	1144	1150	1172	1123	1069	1047	1040	976	966	979	1011	1087	12764
2019-20	1158	1164	1186	1136	1082	1059	1053	989	978	991	1024	1100	12920
2020-21	1172	1178	1200	1149	1094	1071	1073	1009	998	1012	1045	1122	13122
2021-22	1194	1200	1221	1170	1115	1091	1083	1019	1008	1022	1055	1134	13312
2022-23	1206	1212	1233	1181	1125	1102	1093	1029	1018	1032	1066	1145	13442
2023-24	1218	1224	1244	1193	1136	1112	1104	1039	1028	1042	1077	1157	13572
2024-25	1230	1236	1256	1204	1146	1122	1114	1049	1038	1052	1087	1168	13702
2025-26	1242	1248	1267	1215	1157	1133	1124	1059	1048	1062	1097	1179	13831
2026-27	1254	1260	1279	1226	1168	1143	1134	1069	1058	1072	1108	1191	13960
2027-28	1265	1272	1291	1237	1178	1153	1144	1079	1067	1082	1118	1202	14089
2028-29	1277	1284	1302	1248	1189	1164	1154	1088	1077	1091	1129	1213	14217
2029-30	1289	1295	1313	1259	1199	1174	1164	1098	1087	1101	1139	1225	14344
2030-31	1301	1308	1325	1271	1210	1185	1175	1109	1098	1112	1151	1237	14480
2031-32	1314	1321	1338	1283	1222	1196	1186	1120	1109	1123	1162	1250	14623
3032-33	1327	1334	1350	1295	1233	1207	1197	1131	1120	1134	1174	1263	14765
2033-34	1340	1347	1363	1307	1245	1218	1208	1142	1131	1146	1186	1275	14907
2034-35	1354	1360	1376	1320	1256	1229	1219	1152	1141	1157	1197	1288	15048
2035-36	1367	1373	1388	1332	1267	1240	1229	1163	1152	1168	1209	1300	15189
2036-37	1380	1387	1401	1344	1279	1251	1240	1174	1163	1179	1220	1313	15329
2037-38	1393	1400	1413	1356	1290	1262	1251	1185	1174	1190	1232	1325	15470
2038-39	1406	1413	1426	1368	1301	1273	1262	1195	1185	1201	1244	1338	15610
2039-40	1419	1426	1438	1380	1313	1284	1273	1206	1196	1212	1255	1350	15751

INDUSTRIAL SALES - GWH
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	232	217	219	217	199	182	217	213	195	194	194	218	2496
2002-03	187	225	205	219	189	199	192	212	195	195	163	203	2383
2003-04	237	202	210	229	242	197	186	213	152	231	199	187	2485
2004-05	229	218	192	190	245	208	190	188	182	195	193	218	2447
2005-06	209	198	216	180	206	251	207	175	204	187	173	245	2451
2006-07	209	205	233	203	187	166	204	188	175	186	187	190	2332
2007-08	232	214	220	209	206	176	175	184	185	195	167	202	2366
2008-09	206	201	210	202	194	158	201	188	171	203	185	184	2303
2009-10	171	218	196	180	163	134	177	174	167	148	147	199	2073
2010-11	181	175	184	183	171	214	185	195	184	200	160	156	2189

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2011-12	173	153	185	162	159	150	161	157	156	155	158	163	1932
2012-13	174	176	176	166	159	158	160	155	154	153	156	162	1947
2013-14	172	175	174	164	157	156	158	153	152	151	154	160	1927
2014-15	172	175	175	166	158	157	159	154	153	152	155	160	1936
2015-16	172	175	175	166	158	157	159	154	153	152	155	160	1937
2016-17	172	175	176	166	158	157	159	154	153	152	155	160	1938
2017-18	172	175	176	166	158	157	159	154	153	152	155	160	1938
2018-19	172	175	176	166	158	158	159	154	153	152	155	160	1939
2019-20	172	175	176	166	158	158	159	154	153	152	155	160	1940
2020-21	172	176	176	166	159	158	159	154	153	152	155	160	1940
2021-22	172	176	176	166	159	158	159	154	153	152	155	160	1941
2022-23	172	176	176	166	159	158	159	155	153	152	155	161	1941
2023-24	172	176	176	166	159	158	159	155	153	152	155	161	1942
2024-25	172	176	176	166	159	158	159	155	153	152	155	161	1942
2025-26	172	176	176	166	159	158	159	155	153	152	155	161	1943
2026-27	172	176	176	166	159	158	159	155	153	152	155	161	1943
2027-28	172	176	176	167	159	158	160	155	153	153	155	161	1944
2028-29	172	176	176	167	159	158	160	155	153	153	155	161	1945
2029-30	173	176	176	167	159	158	160	155	153	153	156	161	1945
2030-31	173	176	176	167	159	158	160	155	154	153	156	161	1946
2031-32	173	176	176	167	159	158	160	155	154	153	156	161	1946
3032-33	173	176	176	167	159	158	160	155	154	153	156	161	1947
2033-34	173	176	176	167	159	158	160	155	154	153	156	161	1947
2034-35	173	176	176	167	159	158	160	155	154	153	156	161	1948
2035-36	173	176	176	167	159	158	160	155	154	153	156	161	1949
2036-37	173	176	177	167	159	158	160	155	154	153	156	161	1949
2037-38	173	176	177	167	159	158	160	155	154	153	156	161	1950
2038-39	173	176	177	167	159	158	160	155	154	153	156	161	1950
2039-40	173	176	177	167	159	159	160	155	154	153	156	161	1951

R-1 wo LOW INCOME AND LIFE LINE SALES - GWH
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	442	492	470	490	423	454	470	482	407	406	370	403	5310
2002-03	432	503	492	505	427	449	469	472	432	435	406	447	5469
2003-04	499	616	627	596	498	531	542	539	460	462	453	501	6324
2004-05	500	583	599	589	487	534	570	545	467	476	431	477	6258
2005-06	507	624	625	574	482	520	557	551	496	520	461	515	6431
2006-07	630	759	687	610	503	536	577	589	501	492	458	510	6852
2007-08	558	663	685	649	512	551	584	610	527	500	468	534	6841
2008-09	609	702	660	660	547	553	567	574	490	475	445	487	6769
2009-10	513	621	640	640	514	530	535	549	472	449	414	450	6327
2010-11	470	535	537	578	486	519	519	528	454	462	415	436	5939

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2011-12	464	559	612	575	472	515	560	542	493	461	444	459	6157
2012-13	514	573	599	556	499	500	549	538	488	455	438	453	6163
2013-14	508	568	593	549	490	490	541	531	481	448	431	447	6077
2014-15	510	575	591	554	489	488	540	530	478	444	427	445	6069
2015-16	509	574	590	553	487	485	539	529	477	442	425	443	6053
2016-17	507	574	590	552	485	483	538	529	476	441	423	441	6040
2017-18	507	575	592	555	487	486	542	534	481	445	427	446	6076
2018-19	512	582	599	561	492	491	548	540	487	450	432	451	6144
2019-20	518	589	606	567	497	496	554	547	492	455	436	455	6211
2020-21	523	595	612	572	501	500	560	552	497	459	440	459	6271
2021-22	528	601	618	578	505	505	565	558	503	464	444	463	6332
2022-23	532	607	624	583	509	509	571	564	508	468	449	468	6391
2023-24	537	613	630	588	514	514	576	570	513	473	453	472	6454
2024-25	543	619	637	594	519	519	583	577	519	478	458	477	6522
2025-26	548	626	643	600	523	524	589	583	525	483	462	481	6586
2026-27	553	632	650	606	528	529	595	589	531	488	467	486	6653
2027-28	558	638	656	612	533	534	601	596	537	493	472	490	6720
2028-29	564	645	663	617	538	539	607	602	542	498	476	495	6788
2029-30	569	651	669	623	543	544	614	609	548	504	481	500	6855
2030-31	574	658	676	629	548	550	620	615	554	509	486	505	6925
2031-32	580	665	683	636	553	555	627	622	561	515	491	510	6997
3032-33	586	672	690	642	559	560	633	629	567	520	496	515	7069
2033-34	592	678	697	648	564	566	640	636	573	526	501	520	7141
2034-35	597	685	704	655	569	571	646	643	580	531	506	525	7213
2035-36	603	692	711	661	574	577	653	650	586	537	511	530	7286
2036-37	609	699	719	667	580	582	660	657	592	543	517	535	7359
2037-38	615	706	726	674	585	588	666	664	599	548	522	540	7433
2038-39	621	713	733	680	590	593	673	671	605	554	527	545	7506
2039-40	626	721	740	687	596	599	680	678	612	560	532	551	7580

LIFELINE SALES - GWH
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	30	36	32	36	29	34	33	37	28	31	26	30	382
2002-03	29	36	33	36	29	33	32	35	27	30	26	31	376
2003-04	31	40	38	38	30	36	34	37	29	32	27	33	406
2004-05	30	38	36	37	30	36	36	37	29	32	26	31	398
2005-06	30	39	36	36	28	34	33	36	30	34	28	32	398
2006-07	35	46	38	36	28	34	34	38	30	31	26	31	408
2007-08	32	41	39	40	30	35	35	40	32	32	28	34	419
2008-09	36	44	39	41	33	37	37	41	33	34	30	35	439
2009-10	34	43	43	46	38	41	41	44	37	36	32	36	473
2010-11	37	43	42	46	39	43	45	47	39	40	35	38	493

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2011-12	39	47	37	38	33	38	45	43	39	37	35	37	468
2012-13	41	46	48	44	40	40	44	43	39	36	35	36	489
2013-14	40	45	47	43	39	39	43	42	38	35	34	35	480
2014-15	40	45	47	44	39	38	43	42	38	35	34	35	479
2015-16	40	45	47	44	39	38	43	42	38	35	34	35	479
2016-17	40	46	47	44	39	38	43	42	38	35	34	35	480
2017-18	40	46	47	44	39	39	43	42	38	35	34	35	482
2018-19	40	46	47	44	39	39	43	43	38	35	34	35	483
2019-20	40	46	47	44	39	39	43	43	38	35	34	35	485
2020-21	41	46	48	45	39	39	44	43	39	36	34	35	487
2021-22	41	47	48	45	39	39	44	44	39	36	34	36	492
2022-23	41	47	49	45	40	40	45	44	39	36	35	36	497
2023-24	42	48	49	46	40	40	45	44	40	37	35	37	502
2024-25	42	48	50	46	40	40	45	45	40	37	35	37	507
2025-26	43	49	50	47	41	41	46	45	41	38	36	37	513
2026-27	43	49	51	47	41	41	46	46	41	38	36	38	518
2027-28	43	50	51	48	42	42	47	47	42	38	37	38	523
2028-29	44	50	52	48	42	42	47	47	42	39	37	38	529
2029-30	44	51	52	49	42	42	48	48	43	39	37	39	534
2030-31	45	51	53	49	43	43	48	48	43	40	38	39	540
2031-32	45	52	53	50	43	43	49	49	44	40	38	40	545
3032-33	46	52	54	50	44	44	50	49	44	40	38	40	551
2033-34	46	53	54	51	44	44	50	50	45	41	39	40	557
2034-35	46	53	55	51	44	45	51	50	45	41	39	41	562
2035-36	47	54	56	52	45	45	51	51	46	42	40	41	568
2036-37	47	55	56	52	45	45	52	51	46	42	40	42	574
2037-38	48	55	57	53	46	46	52	52	47	43	41	42	580
2038-39	48	56	57	53	46	46	53	52	47	43	41	42	586
2039-40	49	56	58	54	46	47	53	53	48	44	41	43	592

LOW INCOME SALES - GWH
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	66	62	69	62	66	62	75	67	66	56	60	56	767
2002-03	69	66	76	68	71	64	78	68	34	30	34	31	688
2003-04	40	43	50	41	42	40	47	41	39	33	32	30	477
2004-05	31	34	39	34	34	34	41	34	34	30	29	28	402
2005-06	33	35	38	30	30	29	32	27	27	25	26	25	358
2006-07	34	37	37	29	27	24	33	32	29	27	27	26	362
2007-08	31	33	37	33	30	30	34	34	32	27	28	29	379
2008-09	36	37	39	35	35	37	47	43	41	37	40	40	466
2009-10	48	52	61	55	51	49	57	52	51	43	47	48	613
2010-11	58	58	68	63	62	59	73	66	67	58	62	55	747

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2011-12	70	70	83	70	73	68	75	73	67	62	60	61	831
2012-13	69	76	80	74	67	67	74	72	65	61	58	60	823
2013-14	68	76	79	73	65	65	72	71	64	59	57	59	808
2014-15	68	76	79	74	65	65	72	70	64	59	57	59	806
2015-16	68	76	79	74	65	65	72	71	64	59	57	59	807
2016-17	68	77	79	74	65	65	72	71	64	59	57	59	808
2017-18	68	77	79	74	65	65	72	71	64	59	57	59	811
2018-19	68	77	80	74	65	65	73	72	64	59	57	59	814
2019-20	68	78	80	75	65	65	73	72	65	59	57	59	816
2020-21	68	78	80	75	66	66	74	73	65	60	57	60	821
2021-22	69	79	81	76	66	66	74	73	66	61	58	60	829
2022-23	70	80	82	76	67	67	75	74	66	61	58	61	837
2023-24	70	80	83	77	67	67	76	75	67	62	59	61	845
2024-25	71	81	84	78	68	68	77	76	68	62	60	62	854
2025-26	72	82	85	79	69	69	77	77	69	63	60	63	863
2026-27	72	83	85	80	69	69	78	77	70	64	61	63	872
2027-28	73	84	86	80	70	70	79	78	70	65	62	64	881
2028-29	74	85	87	81	71	71	80	79	71	65	62	65	890
2029-30	74	85	88	82	71	71	81	80	72	66	63	65	899
2030-31	75	86	89	83	72	72	82	81	73	67	63	66	908
2031-32	76	87	90	84	73	73	82	82	74	67	64	67	918
3032-33	77	88	91	84	73	74	83	83	74	68	65	67	928
2033-34	77	89	92	85	74	74	84	84	75	69	66	68	937
2034-35	78	90	93	86	75	75	85	85	76	70	66	69	947
2035-36	79	91	94	87	75	76	86	86	77	70	67	69	957
2036-37	80	92	95	88	76	77	87	86	78	71	68	70	967
2037-38	81	93	96	89	77	77	88	87	79	72	68	71	977
2038-39	81	94	97	90	78	78	89	88	80	73	69	71	986
2039-40	82	95	98	90	78	79	90	89	80	73	70	72	996

A-1 SALES - GWH
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	256	253	256	253	236	227	233	224	222	218	218	234	2829
2002-03	250	258	249	245	231	300	170	235	211	254	179	238	2820
2003-04	252	271	269	251	243	233	244	218	225	226	233	241	2906
2004-05	246	260	258	244	221	239	238	215	218	218	219	239	2816
2005-06	249	268	254	246	226	240	240	221	225	219	221	251	2861
2006-07	268	276	262	244	233	236	239	222	222	225	230	213	2871
2007-08	253	264	274	243	237	232	232	227	223	229	215	238	2866
2008-09	260	264	250	250	234	232	227	225	210	209	214	226	2802
2009-10	238	252	256	348	123	224	227	224	205	214	206	226	2743
2010-11	237	238	248	244	221	227	234	225	215	215	218	224	2746

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2011-12	245	252	253	247	233	235	244	231	225	223	227	241	2856
2012-13	257	263	269	257	243	239	243	231	224	222	226	240	2914
2013-14	256	262	268	256	241	238	243	231	224	223	227	240	2909
2014-15	259	267	272	259	242	238	242	230	222	221	225	240	2916
2015-16	258	266	271	258	242	237	242	229	222	220	224	239	2909
2016-17	258	266	271	258	241	237	241	229	221	220	224	238	2904
2017-18	258	266	272	259	242	238	243	231	223	222	226	241	2920
2018-19	261	269	275	261	245	241	246	233	226	225	229	244	2953
2019-20	264	272	278	264	247	244	248	236	229	227	231	247	2987
2020-21	266	275	281	267	250	246	252	240	232	231	235	251	3026
2021-22	271	279	285	271	254	250	255	242	235	233	237	253	3065
2022-23	273	282	287	274	256	252	257	245	237	235	239	255	3092
2023-24	276	285	290	276	258	254	259	247	239	237	242	258	3121
2024-25	278	287	293	279	261	256	261	249	241	240	244	260	3149
2025-26	281	290	295	281	263	259	264	252	244	242	246	263	3177
2026-27	283	293	298	283	265	261	266	254	246	244	248	265	3206
2027-28	286	295	300	286	267	263	268	256	248	246	251	267	3234
2028-29	288	298	303	288	270	265	271	259	250	248	253	270	3263
2029-30	291	300	305	291	272	268	273	261	253	250	255	272	3291
2030-31	293	303	308	293	274	270	275	263	255	253	257	275	3321
2031-32	296	306	311	296	277	272	278	266	257	255	260	277	3352
3032-33	299	309	314	299	279	275	280	268	260	258	262	280	3383
2033-34	302	312	317	301	282	277	283	271	262	260	265	283	3414
2034-35	304	315	319	304	284	280	285	273	265	263	267	285	3445
2035-36	307	318	322	307	286	282	288	276	267	265	270	288	3476
2036-37	310	321	325	309	289	284	290	278	270	267	272	290	3507
2037-38	313	324	328	312	291	287	293	281	272	270	275	293	3538
2038-39	316	326	331	315	294	289	295	283	275	272	277	296	3569
2039-40	318	329	334	317	296	292	298	286	277	275	280	298	3600

A-2 SALES - GWH
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	327	321	383	266	302	298	264	253	285	257	303	289	3549
2002-03	314	330	328	323	289	299	292	286	262	271	274	306	3574
2003-04	342	342	345	332	312	296	291	276	270	293	307	325	3732
2004-05	325	346	345	329	293	306	296	274	282	283	288	319	3686
2005-06	327	351	340	327	300	310	302	276	283	274	288	335	3713
2006-07	357	375	349	334	310	301	309	271	289	287	297	312	3792
2007-08	344	346	365	336	314	291	294	294	281	288	302	320	3775
2008-09	356	345	361	346	326	299	289	291	270	269	294	300	3745
2009-10	301	274	317	319	291	272	267	265	246	256	259	283	3349
2010-11	287	288	303	305	279	230	269	259	244	252	264	265	3247

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2011-12	295	290	297	274	249	230	247	233	229	231	237	253	3066
2012-13	267	270	274	263	251	246	246	233	229	230	237	252	2999
2013-14	266	269	273	262	251	246	248	234	230	231	238	253	3001
2014-15	270	274	278	266	252	247	246	232	228	230	236	253	3011
2015-16	270	273	278	265	251	246	246	232	227	229	235	252	3004
2016-17	269	272	277	265	251	246	246	231	227	229	235	251	2999
2017-18	269	272	278	266	252	247	247	233	229	231	237	254	3016
2018-19	272	276	281	269	255	250	250	236	232	233	240	257	3050
2019-20	275	279	284	272	258	253	253	238	234	236	243	260	3085
2020-21	278	282	287	274	260	255	257	243	239	241	248	265	3129
2021-22	283	287	292	279	265	260	260	245	241	243	250	268	3171
2022-23	286	289	294	282	267	262	262	247	243	245	252	270	3200
2023-24	288	292	297	284	269	264	264	250	245	247	255	273	3229
2024-25	291	295	300	287	272	267	266	252	248	250	257	275	3258
2025-26	294	298	302	289	274	269	269	254	250	252	259	278	3287
2026-27	296	300	305	292	276	271	271	257	252	254	262	280	3316
2027-28	299	303	308	294	279	273	273	259	254	256	264	283	3345
2028-29	302	306	310	297	281	276	276	261	257	258	266	285	3374
2029-30	304	308	313	299	283	278	278	263	259	261	269	288	3403
2030-31	307	311	315	302	286	280	280	266	261	263	271	291	3433
2031-32	310	314	318	304	288	283	283	268	264	266	274	293	3465
3032-33	313	317	321	307	291	285	285	271	266	268	276	296	3497
2033-34	316	320	324	310	294	288	288	273	269	271	279	299	3529
2034-35	319	323	327	313	296	290	290	276	271	273	281	302	3561
2035-36	321	326	330	315	299	293	293	278	274	276	284	305	3592
2036-37	324	329	332	318	301	295	295	281	276	278	287	307	3624
2037-38	327	332	335	321	304	298	298	283	279	280	289	310	3655
2038-39	330	335	338	323	306	300	300	285	281	283	292	313	3687
2039-40	333	338	341	326	309	303	303	288	283	285	294	316	3719

A-3 SALES - GWH
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	731	660	724	676	677	615	615	618	622	647	565	754	7905
2002-03	785	606	680	727	669	671	677	638	596	613	683	678	8023
2003-04	641	746	748	731	736	640	733	556	627	642	660	686	8146
2004-05	705	726	720	711	669	695	662	610	626	630	641	706	8101
2005-06	715	733	720	730	680	719	668	633	623	630	649	735	8236
2006-07	776	770	780	743	737	727	656	653	663	659	683	703	8552
2007-08	790	763	821	754	725	727	699	682	680	700	699	732	8774
2008-09	952	624	814	803	769	705	684	697	633	669	691	708	8749
2009-10	750	721	806	779	744	677	716	689	650	659	670	721	8582
2010-11	753	718	770	763	700	696	703	706	670	700	680	689	8548

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2011-12	756	722	774	756	724	693	708	667	657	664	687	734	8541
2012-13	771	776	789	757	726	711	707	666	655	662	685	731	8636
2013-14	768	773	786	754	724	709	711	670	659	666	688	734	8644
2014-15	781	787	801	764	727	712	707	665	654	661	683	732	8673
2015-16	779	785	799	763	725	711	706	664	652	660	682	730	8655
2016-17	777	783	798	762	725	710	706	663	651	658	680	729	8640
2017-18	776	783	800	764	727	713	710	667	656	664	687	737	8686
2018-19	785	792	808	772	735	721	717	675	664	672	695	746	8782
2019-20	794	801	817	780	743	729	725	682	671	679	703	754	8878
2020-21	802	810	825	788	751	736	737	694	683	692	715	767	9000
2021-22	815	823	838	801	763	748	744	701	690	698	722	774	9116
2022-23	823	830	845	808	769	754	750	707	696	704	728	781	9195
2023-24	830	838	852	815	776	761	756	713	702	710	735	788	9275
2024-25	837	845	859	822	782	767	762	719	708	716	741	795	9355
2025-26	845	852	866	828	789	773	769	725	714	722	748	802	9434
2026-27	852	860	873	835	795	780	775	731	720	728	754	809	9513
2027-28	859	867	881	842	802	786	781	737	726	734	760	816	9592
2028-29	867	874	888	849	808	792	787	744	732	740	767	823	9671
2029-30	874	882	894	856	815	799	793	750	738	746	773	830	9749
2030-31	881	889	902	863	821	805	800	756	745	753	780	837	9832
2031-32	889	897	910	870	828	812	807	763	751	760	787	845	9920
3032-33	897	905	917	878	836	819	813	770	758	767	794	853	10007
2033-34	905	913	925	885	843	826	820	776	765	774	802	861	10094
2034-35	913	921	933	893	850	833	827	783	772	780	809	868	10181
2035-36	921	929	941	900	856	839	834	789	778	787	816	876	10267
2036-37	929	937	948	907	863	846	840	796	785	794	823	883	10353
2037-38	937	945	956	915	870	853	847	803	792	801	830	891	10439
2038-39	945	953	964	922	877	860	854	809	798	807	837	899	10525
2039-40	953	961	971	930	884	866	860	816	805	814	844	906	10611

EXPERIMENTAL RATES - ELECTRICITY SALES - GWH
(Includes Real Time Pricing, Contract Demand, and Guarantee Load Factor)
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	85	89	89	87	80	72	105	83	76	77	83	87	1014
2002-03	64	99	86	100	71	80	89	105	84	89	56	94	1017
2003-04	110	72	89	100	120	85	79	107	51	126	90	79	1109
2004-05	118	94	83	88	129	97	89	101	88	94	87	118	1184
2005-06	98	84	105	75	96	148	111	83	111	92	73	122	1199
2006-07	96	90	113	103	83	73	98	92	83	97	91	99	1119
2007-08	100	100	105	97	103	77	90	89	85	87	80	108	1121
2008-09	96	91	101	94	98	65	120	95	88	91	87	93	1119
2009-10	60	124	93	65	65	54	72	68	68	55	50	88	863
2010-11	67	73	70	76	73	58	83	79	70	69	75	63	856

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2011-12	82	67	90	82	70	84	80	77	77	77	78	82	947
2012-13	87	88	88	84	80	79	80	77	76	76	78	81	973
2013-14	86	87	87	83	79	79	79	76	76	76	77	81	967
2014-15	87	88	88	84	80	79	79	76	76	76	77	81	971
2015-16	87	88	88	84	80	79	79	76	76	76	77	81	970
2016-17	86	88	88	84	80	79	79	76	76	76	77	81	970
2017-18	86	88	88	84	80	79	80	77	76	76	78	81	972
2018-19	87	88	89	84	80	80	80	77	76	76	78	81	976
2019-20	87	88	89	85	81	80	80	77	76	76	78	82	980
2020-21	87	89	89	85	81	80	81	78	77	77	79	82	984
2021-22	88	89	90	85	81	81	81	78	77	77	79	82	989
2022-23	88	90	90	86	82	81	81	78	77	77	79	83	992
2023-24	89	90	90	86	82	81	81	78	78	78	79	83	995
2024-25	89	90	91	86	82	81	82	78	78	78	80	83	998
2025-26	89	90	91	86	82	82	82	79	78	78	80	84	1001
2026-27	89	91	91	87	83	82	82	79	78	78	80	84	1004
2027-28	90	91	92	87	83	82	82	79	78	78	80	84	1007
2028-29	90	91	92	87	83	82	83	79	79	79	81	84	1010
2029-30	90	92	92	87	83	82	83	80	79	79	81	85	1013
2030-31	90	92	92	88	84	83	83	80	79	79	81	85	1016
2031-32	91	92	93	88	84	83	83	80	79	79	81	85	1019
3032-33	91	92	93	88	84	83	84	80	80	80	82	85	1023
2033-34	91	93	93	89	84	84	84	81	80	80	82	86	1026
2034-35	92	93	94	89	85	84	84	81	80	80	82	86	1029
2035-36	92	93	94	89	85	84	84	81	80	80	82	86	1033
2036-37	92	94	94	89	85	84	85	81	81	81	83	87	1036
2037-38	93	94	94	90	85	85	85	82	81	81	83	87	1039
2038-39	93	94	95	90	86	85	85	82	81	81	83	87	1042
2039-40	93	95	95	90	86	85	85	82	81	82	84	88	1046

RESIDENTIAL ACCUMULATED ENERGY EFFICIENCY SAVINGS - GWH
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	2	2	2	3	3	3	3	3	3	3	3	3	34
2002-03	3	4	4	4	4	4	3	4	4	4	4	4	45
2003-04	4	5	4	4	4	4	4	4	4	4	5	5	53
2004-05	5	5	5	5	5	5	5	5	5	5	6	6	62
2005-06	6	6	6	6	6	6	5	6	6	6	6	7	71
2006-07	7	7	7	7	7	7	7	7	7	7	8	8	86
2007-08	9	9	9	9	9	9	9	9	10	10	11	12	115
2008-09	13	13	13	13	12	12	14	16	21	22	23	25	195
2009-10	25	26	24	24	23	22	22	22	23	23	24	26	283
2010-11	27	27	25	25	24	23	22	23	24	24	26	28	297

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2011-12	29	30	28	28	27	27	27	28	29	30	32	35	350
2012-13	36	36	34	33	32	31	30	31	32	33	35	37	400
2013-14	38	39	36	36	34	33	33	34	35	35	37	41	432
2014-15	42	42	40	39	38	37	36	38	38	39	42	45	476
2015-16	47	47	45	44	42	41	41	42	43	44	47	51	535
2016-17	53	53	50	50	48	47	46	48	49	50	53	58	605
2017-18	59	59	55	54	51	50	48	50	50	51	54	58	639
2018-19	59	59	55	54	51	50	48	50	50	51	54	58	639
2019-20	59	59	55	54	51	50	48	50	50	51	54	58	639
2020-21	59	59	55	54	51	50	48	50	50	51	54	58	639
2021-22	59	59	55	54	51	50	48	50	50	51	54	58	639
2022-23	59	59	55	54	51	50	48	50	50	51	54	58	639
2023-24	59	59	55	54	51	50	48	50	50	51	54	58	639
2024-25	59	59	55	54	51	50	48	50	50	51	54	58	639
2025-26	59	59	55	54	51	50	48	50	50	51	54	58	639
2026-27	59	59	55	54	51	50	48	50	50	51	54	58	639
2027-28	59	59	55	54	51	50	48	50	50	51	54	58	639
2028-29	59	59	55	54	51	50	48	50	50	51	54	58	639
2029-30	59	59	55	54	51	50	48	50	50	51	54	58	639
2030-31	59	59	55	54	51	50	48	50	50	51	54	58	639
2031-32	59	59	55	54	51	50	48	50	50	51	54	58	639
3032-33	59	59	55	54	51	50	48	50	50	51	54	58	639
2033-34	59	59	55	54	51	50	48	50	50	51	54	58	639
2034-35	59	59	55	54	51	50	48	50	50	51	54	58	639
2035-36	59	59	55	54	51	50	48	50	50	51	54	58	639
2036-37	59	59	55	54	51	50	48	50	50	51	54	58	639
2037-38	59	59	55	54	51	50	48	50	50	51	54	58	639
2038-39	59	59	55	54	51	50	48	50	50	51	54	58	639
2039-40	59	59	55	54	51	50	48	50	50	51	54	58	639

COMMERCIAL ACCUMULATED ENERGY EFFICIENCY SAVINGS - GWH
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	26	27	26	26	26	26	27	28	30	31	33	37	343
2002-03	38	39	36	36	34	34	33	34	35	36	38	41	436
2003-04	43	43	40	39	37	37	36	37	38	38	40	44	472
2004-05	45	45	42	41	40	39	38	39	40	40	43	46	498
2005-06	47	48	45	44	42	41	40	41	42	43	45	49	525
2006-07	50	50	47	46	44	43	42	44	45	46	48	53	559
2007-08	54	55	51	51	48	47	46	48	49	51	55	62	618
2008-09	65	67	64	64	62	61	61	64	66	68	72	78	790
2009-10	82	83	78	77	74	73	72	74	77	78	85	93	946
2010-11	97	98	93	92	87	86	84	87	89	91	99	108	1112

FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2011-12	112	113	107	106	102	100	99	103	105	108	115	125	1295
2012-13	130	131	123	121	116	114	112	117	119	122	129	140	1475
2013-14	145	147	138	136	131	128	126	131	134	137	145	158	1656
2014-15	163	164	155	152	146	143	141	146	149	152	162	175	1848
2015-16	181	182	171	168	161	158	155	161	164	168	178	193	2042
2016-17	199	200	188	185	177	173	170	176	180	183	194	210	2236
2017-18	215	215	201	196	186	181	176	181	183	186	196	210	2325
2018-19	215	215	201	196	186	181	176	181	183	186	196	210	2325
2019-20	215	215	201	196	186	181	176	181	183	186	196	210	2325
2020-21	215	215	201	196	186	181	176	181	183	186	196	210	2325
2021-22	215	215	201	196	186	181	176	181	183	186	196	210	2325
2022-23	215	215	201	196	186	181	176	181	183	186	196	210	2325
2023-24	215	215	201	196	186	181	176	181	183	186	196	210	2325
2024-25	215	215	201	196	186	181	176	181	183	186	196	210	2325
2025-26	215	215	201	196	186	181	176	181	183	186	196	210	2325
2026-27	215	215	201	196	186	181	176	181	183	186	196	210	2325
2027-28	215	215	201	196	186	181	176	181	183	186	196	210	2325
2028-29	215	215	201	196	186	181	176	181	183	186	196	210	2325
2029-30	215	215	201	196	186	181	176	181	183	186	196	210	2325
2030-31	215	215	201	196	186	181	176	181	183	186	196	210	2325
2031-32	215	215	201	196	186	181	176	181	183	186	196	210	2325
3032-33	215	215	201	196	186	181	176	181	183	186	196	210	2325
2033-34	215	215	201	196	186	181	176	181	183	186	196	210	2325
2034-35	215	215	201	196	186	181	176	181	183	186	196	210	2325
2035-36	215	215	201	196	186	181	176	181	183	186	196	210	2325
2036-37	215	215	201	196	186	181	176	181	183	186	196	210	2325
2037-38	215	215	201	196	186	181	176	181	183	186	196	210	2325
2038-39	215	215	201	196	186	181	176	181	183	186	196	210	2325
2039-40	215	215	201	196	186	181	176	181	183	186	196	210	2325

HUFFMAN BILL ACCUMULATED ENERGY EFFICIENCY SAVINGS - GWH
2012 ENERGY AND DEMAND FORECAST
2001-2002 THROUGH 2039-2040
FISCAL YEAR

HISTORICAL

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2001-02	0	0	0	0	0	0	0	0	0	0	0	0	0
2002-03	0	0	0	0	0	0	0	0	0	0	0	0	0
2003-04	0	0	0	0	0	0	0	0	0	0	0	0	0
2004-05	0	0	0	0	0	0	0	0	0	0	0	0	0
2005-06	0	0	0	0	0	0	0	0	0	0	0	0	0
2006-07	0	0	0	0	0	0	0	0	0	0	0	0	0
2007-08	0	0	0	0	0	0	0	0	0	0	0	0	0
2008-09	0	0	0	0	0	0	0	0	0	0	0	0	0
2009-10	0	0	0	0	0	0	0	0	0	0	0	0	0
2010-11	0	0	0	0	0	0	0	0	0	0	0	0	0

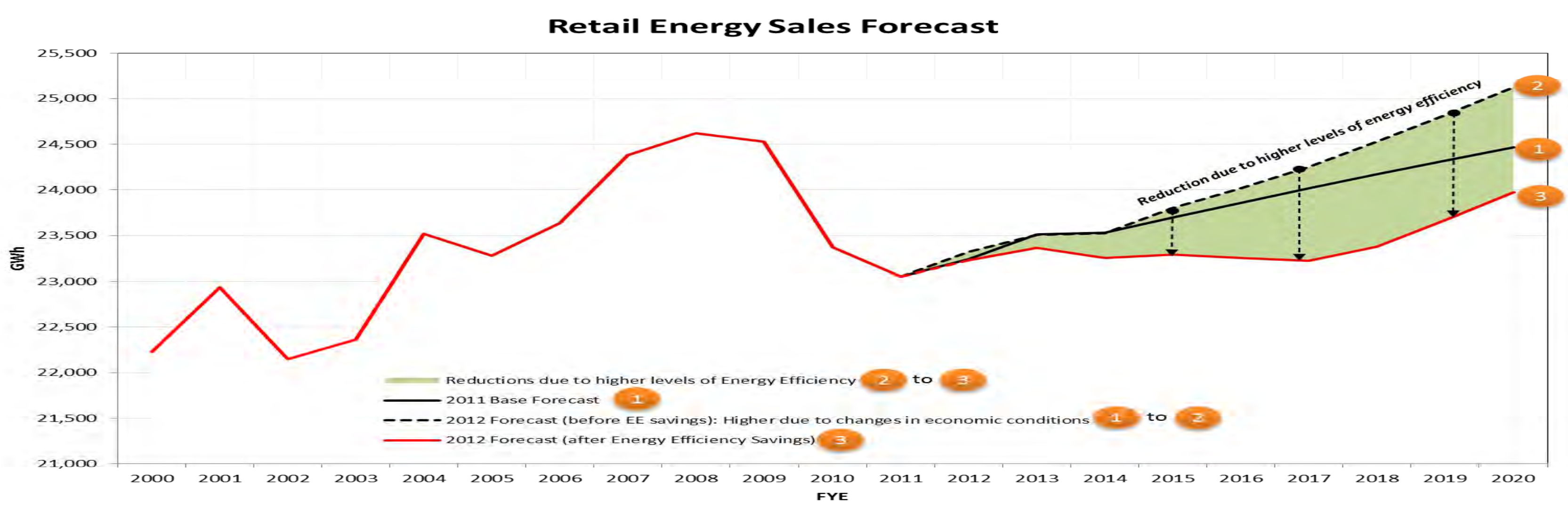
FORECAST

FISCAL YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2011-12	0	0	0	0	0	0	1	1	1	2	2	2	9
2012-13	3	3	4	4	5	6	7	8	9	10	10	9	77
2013-14	10	11	13	14	17	20	20	19	20	20	19	17	201
2014-15	18	18	21	22	25	29	29	26	27	27	25	22	287
2015-16	23	23	27	27	31	35	35	32	32	33	30	27	354
2016-17	27	27	32	32	36	41	40	36	37	37	34	29	408
2017-18	30	30	34	34	38	43	42	38	38	38	35	31	431
2018-19	31	31	35	36	39	45	44	40	40	40	36	32	448
2019-20	32	32	37	37	41	46	46	41	41	42	38	33	466
2020-21	34	34	39	39	43	49	49	44	44	44	40	35	494
2021-22	36	36	41	41	45	52	51	46	46	46	42	37	518
2022-23	37	37	43	43	47	54	53	47	47	48	43	38	536
2023-24	38	38	44	44	48	55	54	48	48	49	44	39	549
2024-25	39	39	44	44	49	56	55	49	49	49	45	39	556
2025-26	39	39	45	45	50	57	56	50	50	50	46	40	566
2026-27	40	40	46	46	50	57	56	51	51	51	46	41	575
2027-28	41	41	46	47	51	58	57	51	51	52	47	41	583
2028-29	41	41	47	47	52	59	58	52	52	52	48	42	592
2029-30	42	42	48	48	53	60	59	53	53	53	48	42	600
2030-31	42	42	48	49	53	61	60	54	54	54	49	43	609
2031-32	43	43	49	49	54	62	60	54	54	54	50	43	617
3032-33	43	44	50	50	55	62	61	55	55	55	50	44	625
2033-34	44	44	50	51	56	63	62	56	56	56	51	45	634
2034-35	45	45	51	51	56	64	63	57	57	57	52	45	642
2035-36	45	45	52	52	57	65	64	57	57	57	52	46	651
2036-37	46	46	53	53	58	66	65	58	58	58	53	46	659
2037-38	46	46	53	53	59	67	65	59	59	59	54	47	667
2038-39	47	47	54	54	59	68	66	60	60	60	54	48	676
2039-40	48	48	55	55	60	68	67	60	60	60	55	48	684

Retail Sales

Key Change Factors from 2011 to 2012 forecast:

- ✓ EE included through FYE 2017
- ✓ EE has contributed to the reduction in the retail sales forecast as part of implementing AB 2021. LADWP has targeted an additional 8.6% reduction by 2020.
- ✓ Construction activity remains at low level for extended period. Construction jobs concentrated on rebuilding infrastructure rather than adding housing units or commercial floor space which would have greater impact on electricity sales.



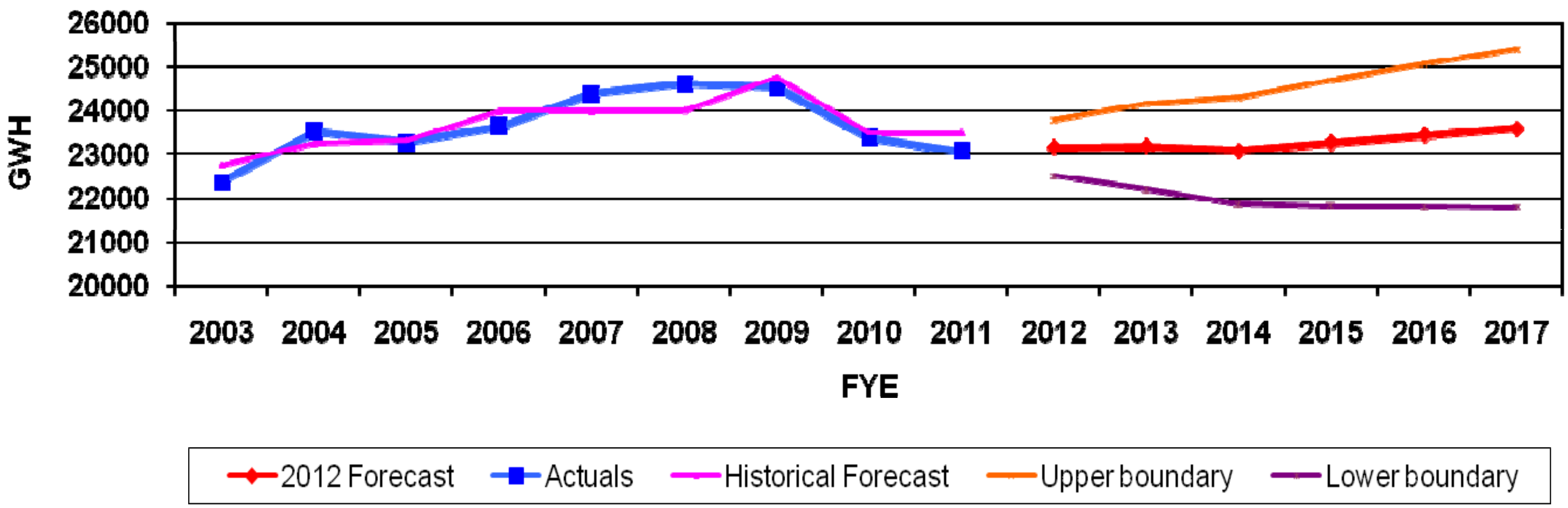
Retail Sales

Accuracy:

✓EE and Solar were not modeled explicitly in Historical Forecasts.

✓Historical accuracy is 0.2% with a 1.6% deviation. However expect larger variation in accuracy due uncertainty of new programs.

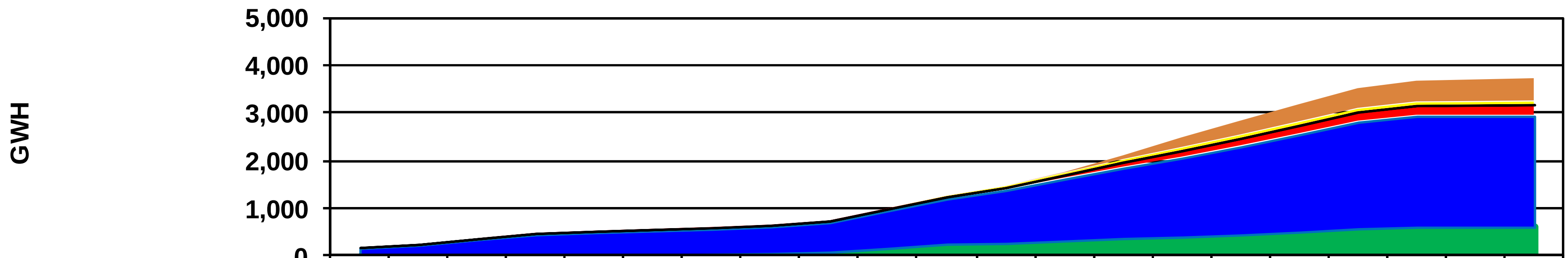
✓Forecast variation is a function of weather, economic forecasts, meeting program goals and model specification.



Energy Efficiency and Solar Rooftops

Historical and Forecasted Accumulated Savings

- ✓ EE before 2008 not included in ECAF Lost Revenue calculation.
- ✓ Energy Efficient Light Bulbs savings are the result of a new State appliance standard. (Huffman)

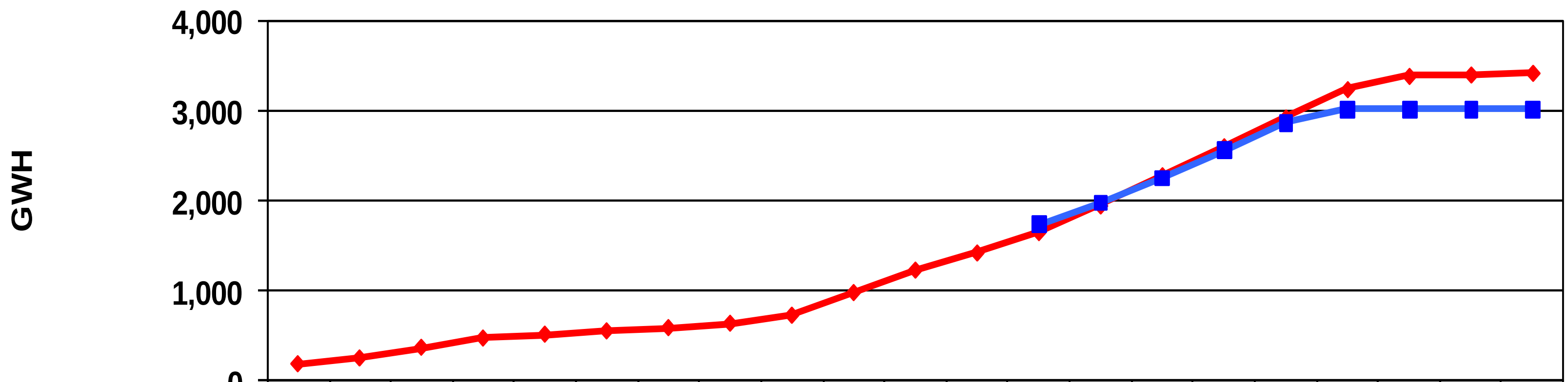


	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Energy Efficient Light Bulbs	0	0	0	0	0	0	0	0	0	0	0	0	9	77	201	287	354	408	431	448	466
LADWP Street Light	0	0	0	0	0	0	0	0	0	0	5	15	25	35	45	50	50	50	50	50	50
LADWP Traffic Light	0	0	0	0	0	0	0	1	2	2	3	4	4	4	4	4	4	4	4	4	4
LADWP Rooftop Solar	0	0	2	9	12	13	14	16	18	22	30	42	70	109	140	161	181	199	210	219	228
LADWP Commercial	179	238	343	436	472	498	525	559	618	790	946	1,112	1,295	1,475	1,656	1,848	2,042	2,236	2,325	2,325	2,325
LADWP Residential	15	21	34	45	53	62	71	86	115	195	283	297	350	400	432	476	535	605	639	639	639

FYE

LADWP Residential | LADWP Commercial | LADWP Rooftop Solar
LADWP Traffic Light | LADWP Street Light | Energy Efficient Light Bulbs

Energy Efficiency Program Change



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
2012 Forecast	195	259	377	481	524	560	596	646	735	987	1,238	1,429	1,654	1,953	2,288	2,611	2,932	3,249	3,395	3,412	3,430
2011 Forecast													1,729	1,972	2,249	2,554	2,869	3,016	3,016	3,016	3,016

FYE

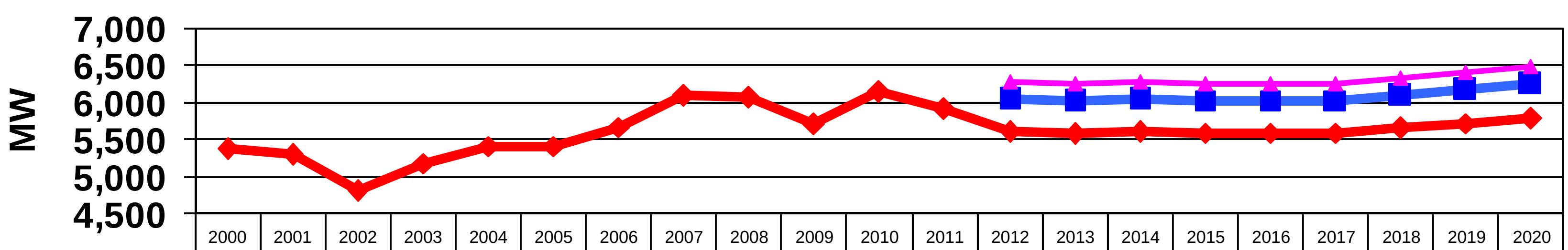
2012 Forecast 2011 Forecast

Peak Demand

Cases:

✓The variance around the 1-in-2 forecasted peak has widened based on events since 2006.

✓Based on the climate change finding, it is now expected that the System will approach its potential more frequently so the distance between the 1-in-10 and 1-in-40 forecasts is compressed.



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1-in-2	5,368	5,299	4,805	5,185	5,410	5,418	5,667	6,102	6,071	5,709	6,142	5,907	5,606	5,577	5,604	5,591	5,590	5,597	5,658	5,725	5,791
1-in-10													6,046	6,014	6,042	6,028	6,026	6,034	6,099	6,172	6,244
1-in-40													6,279	6,245	6,274	6,260	6,257	6,265	6,333	6,409	6,484

1-in-2 1-in-10 1-in-40

Peak Demand

✓Annual peak demand is dependent on the severity of the heat storms that are encountered during the year.

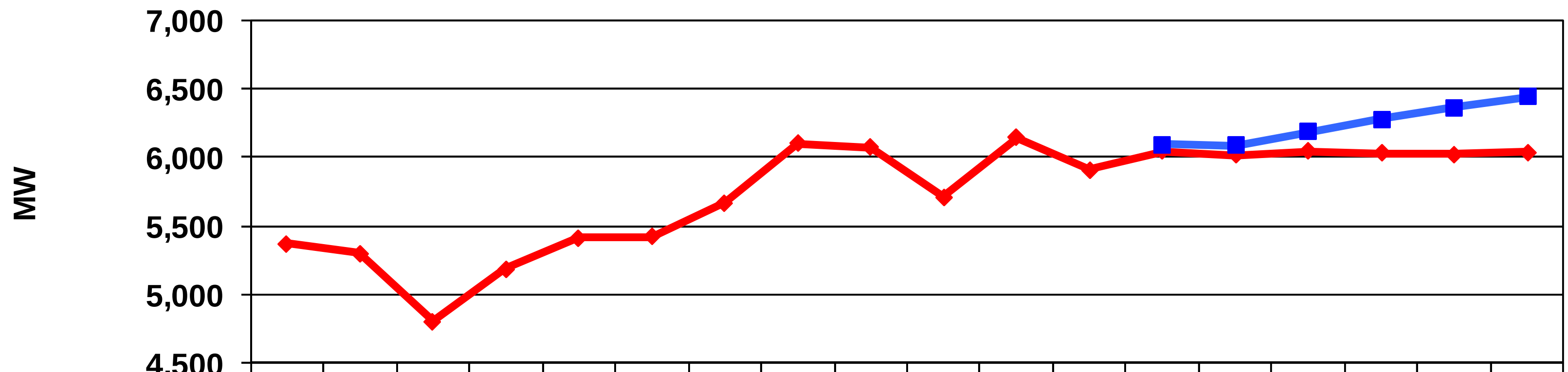
✓The cases are built on the probability of a weather event occurring in a given year.

NEL (MW) Fiscal Year Annual Peak Demand				
Fiscal Year	Base Case	1 in 5	1 in 10	1 in 40 Hot
2012-13	5,606	5,894	6,046	6,279
2013-14	5,577	5,863	6,014	6,245
2014-15	5,604	5,891	6,042	6,274
2015-16	5,591	5,878	6,028	6,260
2016-17	5,590	5,876	6,026	6,257
2017-18	5,597	5,884	6,034	6,265
2018-19	5,658	5,947	6,099	6,333
2019-00	5,725	6,018	6,172	6,409
2020-21	5,791	6,088	6,244	6,484
2021-22	5,881	6,184	6,342	6,586
2022-23	5,942	6,248	6,409	6,656
2023-24	5,995	6,305	6,467	6,716
2024-25	6,050	6,363	6,526	6,779
2025-26	6,105	6,421	6,586	6,840
2026-27	6,160	6,478	6,645	6,902
2027-28	6,216	6,537	6,705	6,965
2028-29	6,271	6,595	6,765	7,027
2029-30	6,326	6,653	6,824	7,088
2030-31	6,381	6,712	6,885	7,151

1-in-10 Peak Demand

1-in-10 peak used in Integrated Resource Planning process:

- ✓2011 Actual Peak = 5907 MW.
- ✓2011 Weather-Normalized peak = 5631 MW.
- ✓2011 Forecasted Weather-normalized peak = 5589 MW.
- ✓Peaks after 2006 have tended to spike.



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
2012 Forecast	5,368	5,299	4,805	5,185	5,410	5,418	5,667	6,102	6,071	5,709	6,142	5,907	6,046	6,014	6,042	6,028	6,026	6,034
2011 Forecast													6,092	6,089	6,188	6,277	6,365	6,442

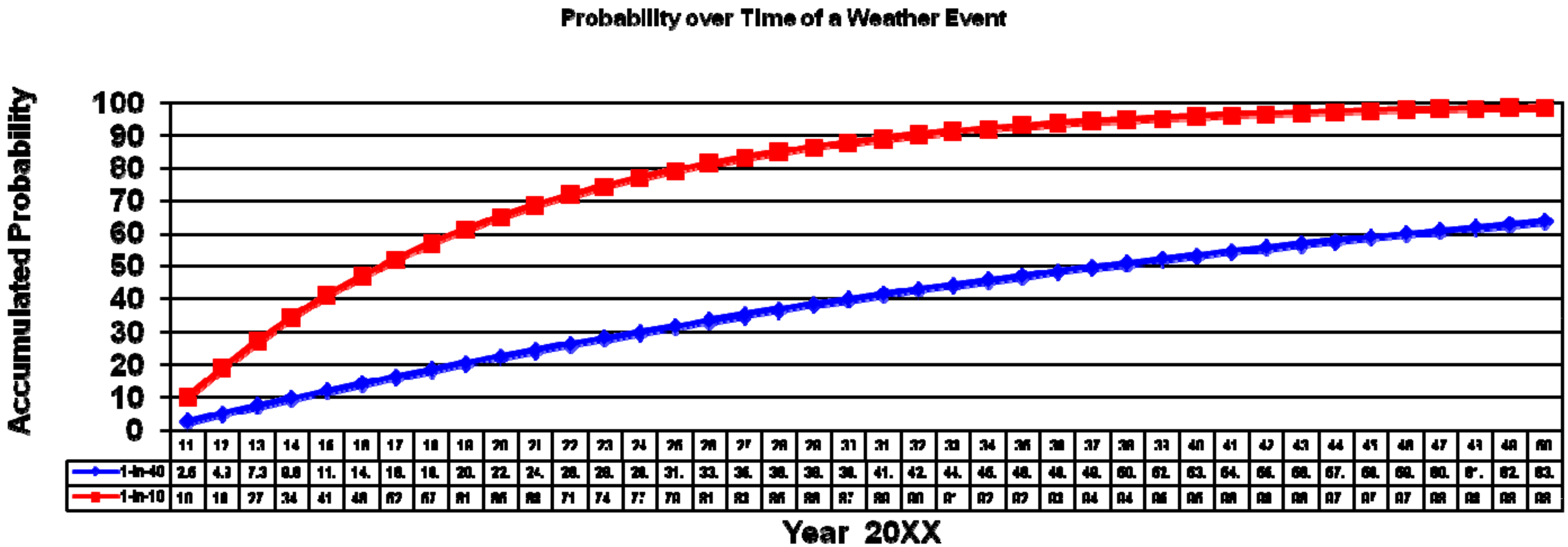
FYE

2012 Forecast 2011 Forecast

1-in-10 Peak Demand

Probability accumulates over time:

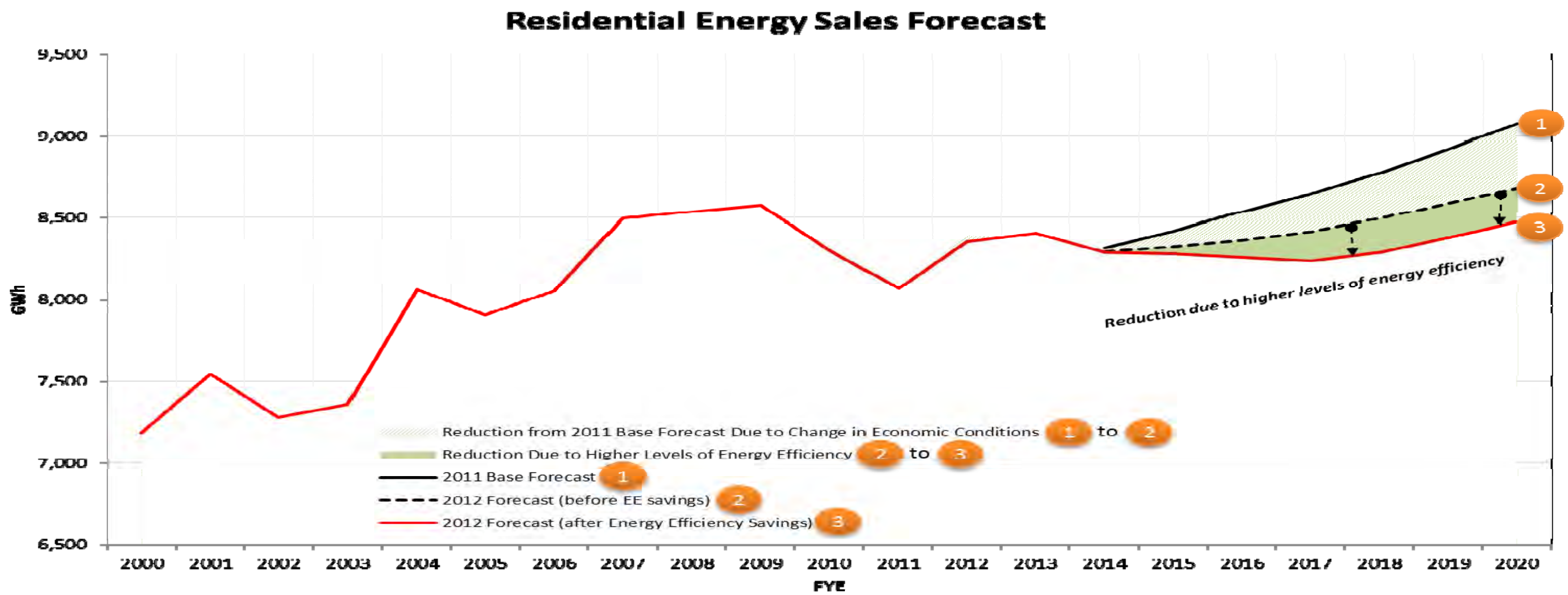
- ✓There is a 65% chance of having a 1-in-10 weather event by 2020.
- ✓There is a 22% chance of having a 1-in-40 weather event by 2020.
- ✓$P_t=1-(1-P_e)^t$



Residential Energy Sales

Components of Change

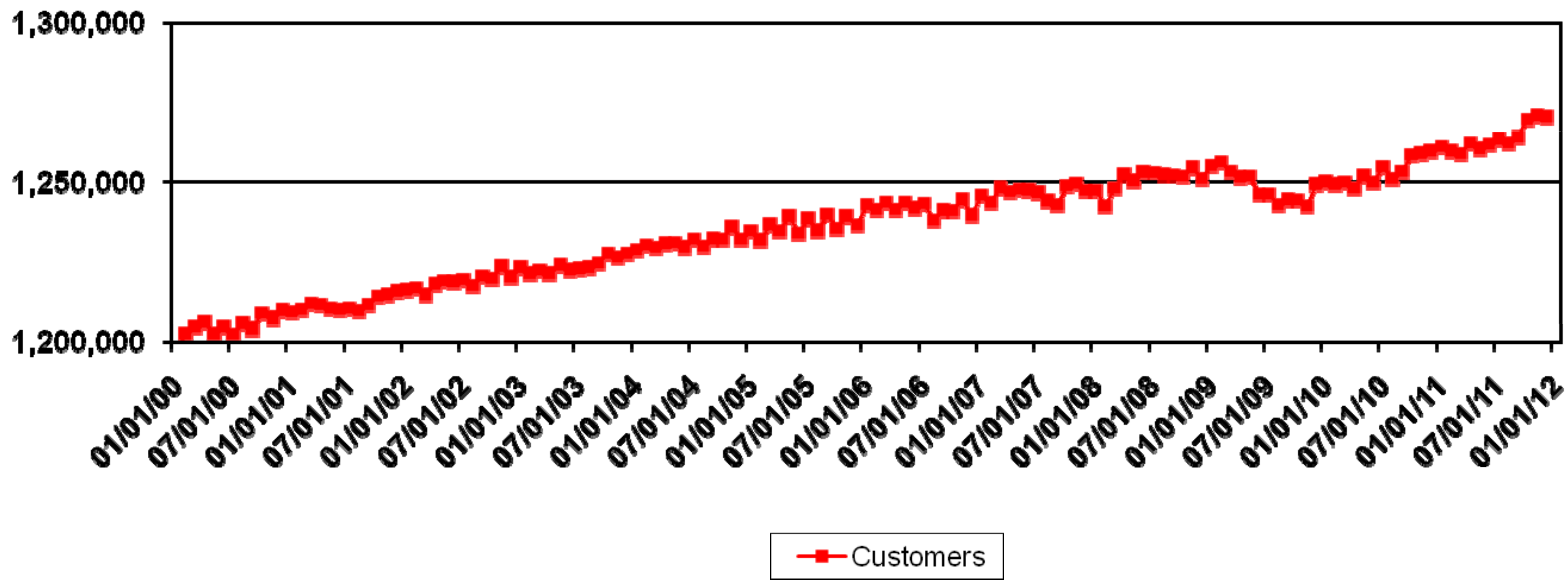
- ✓ Lowered new-units-built forecast
- ✓ Lower economic forecast



Residential Energy Sales
Number of Residential Customers

Recent Evidence

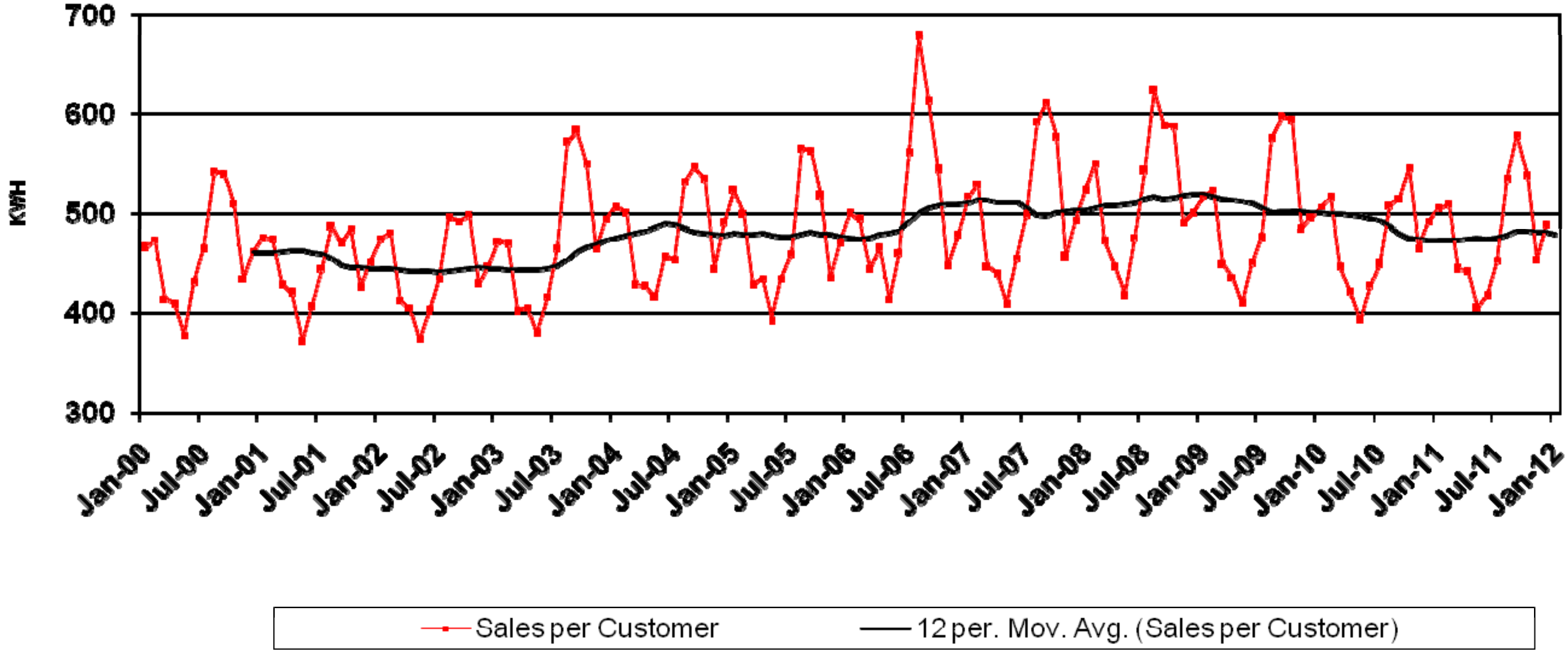
- ✓ 10,000 active meters added in 2011.
- ✓ Returning to long-term trend quickly.
- ✓ The majority of residential customers are renters and live in multi-family units.
- ✓ The attractiveness of downtown living has increased due to the “Housing that Works” plan.



Residential Energy Sales
Average Sales per Customer

Recent Evidence

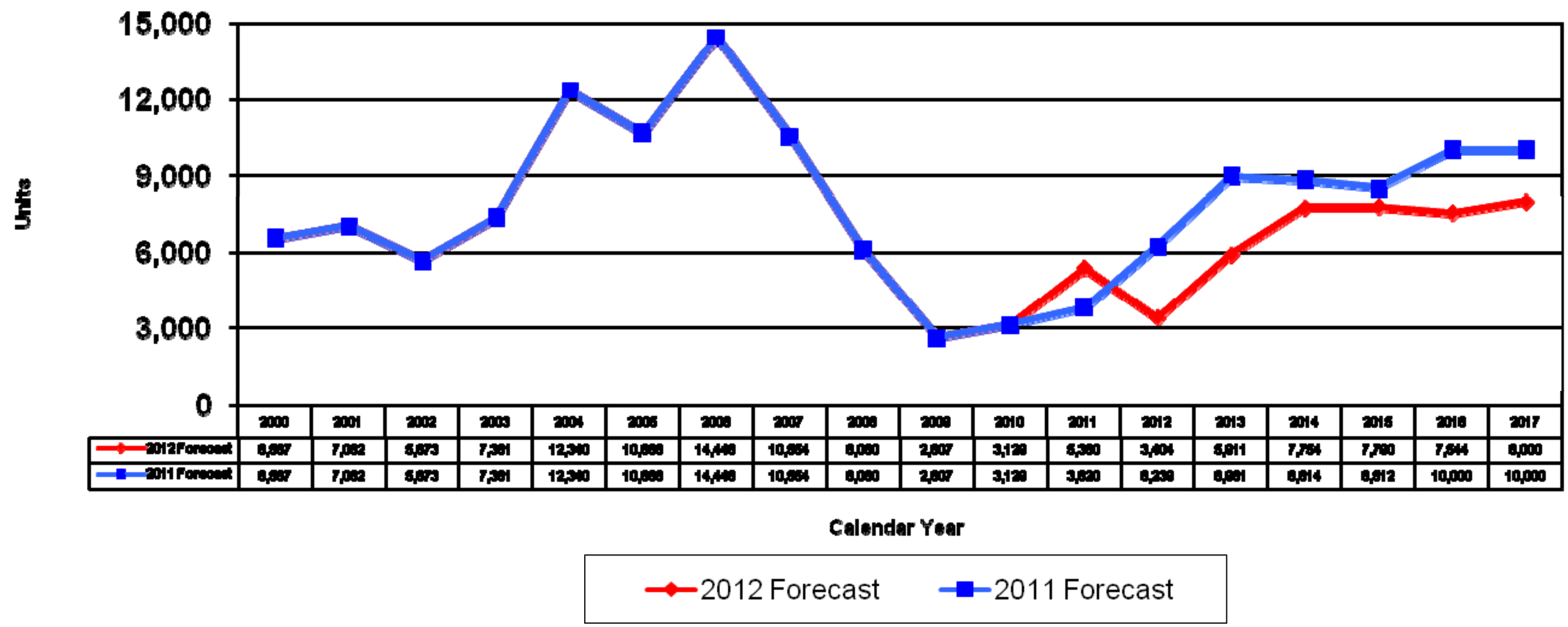
- ✓Sales per residential customer reached an all-time high of 519 KWH per month in December 2008.
- ✓The December 2011 rate is 482 KWH per Month.
- ✓Weather -normalized September 2011 rate is 495 kWh per Month.



Residential Energy Sales
New Residential Building Units

Recent Evidence

- ✓ New units are 20% Single-Family and 80% Multi-family which lowers future average consumption per household.
- ✓ Recent Housing Starts are at historical lows.

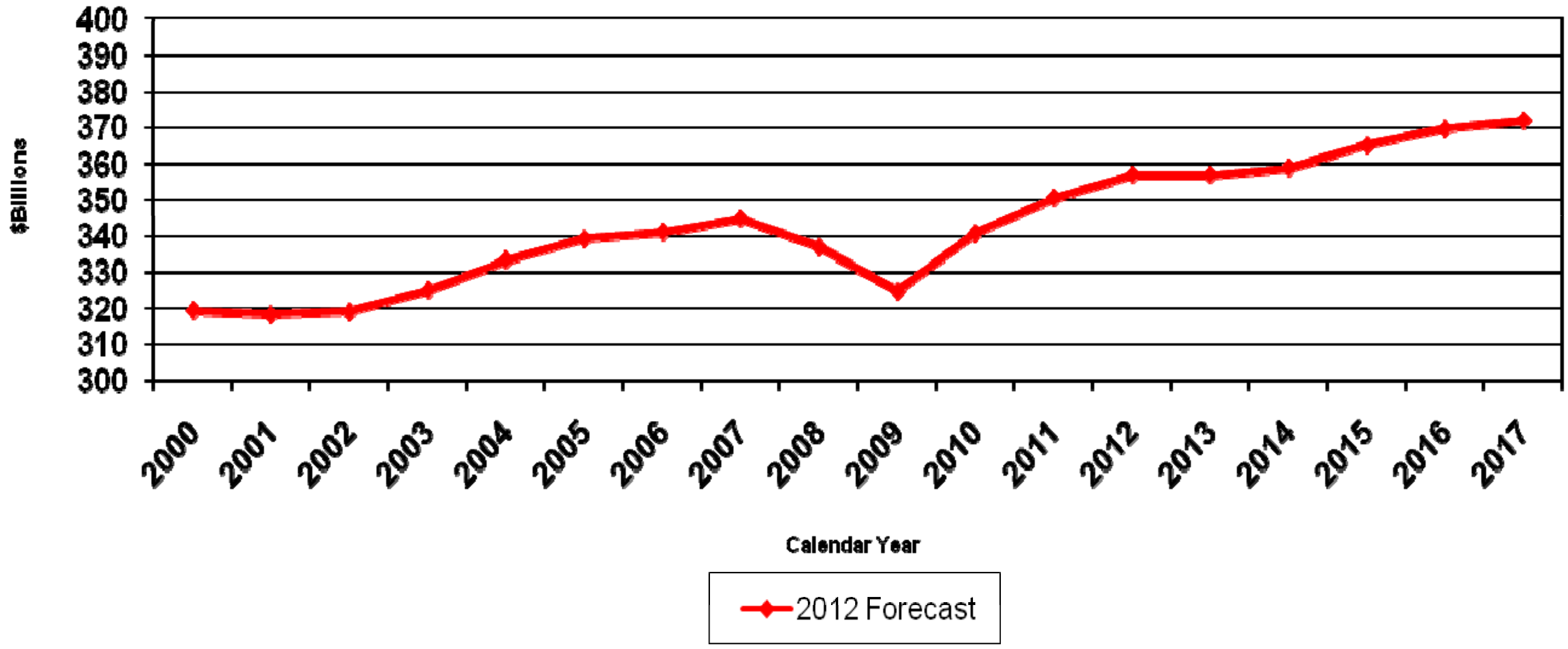


	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
2012 Forecast	6,567	7,062	5,673	7,361	12,340	10,666	14,446	10,554	6,080	2,607	3,129	5,360	3,404	5,911	7,754	7,760	7,544	8,000
2011 Forecast	6,567	7,062	5,673	7,361	12,340	10,666	14,446	10,554	6,080	2,607	3,129	3,820	6,239	8,961	8,814	8,512	10,000	10,000

Residential Energy Sales
Recent Economic Impact

Real Personal Consumption

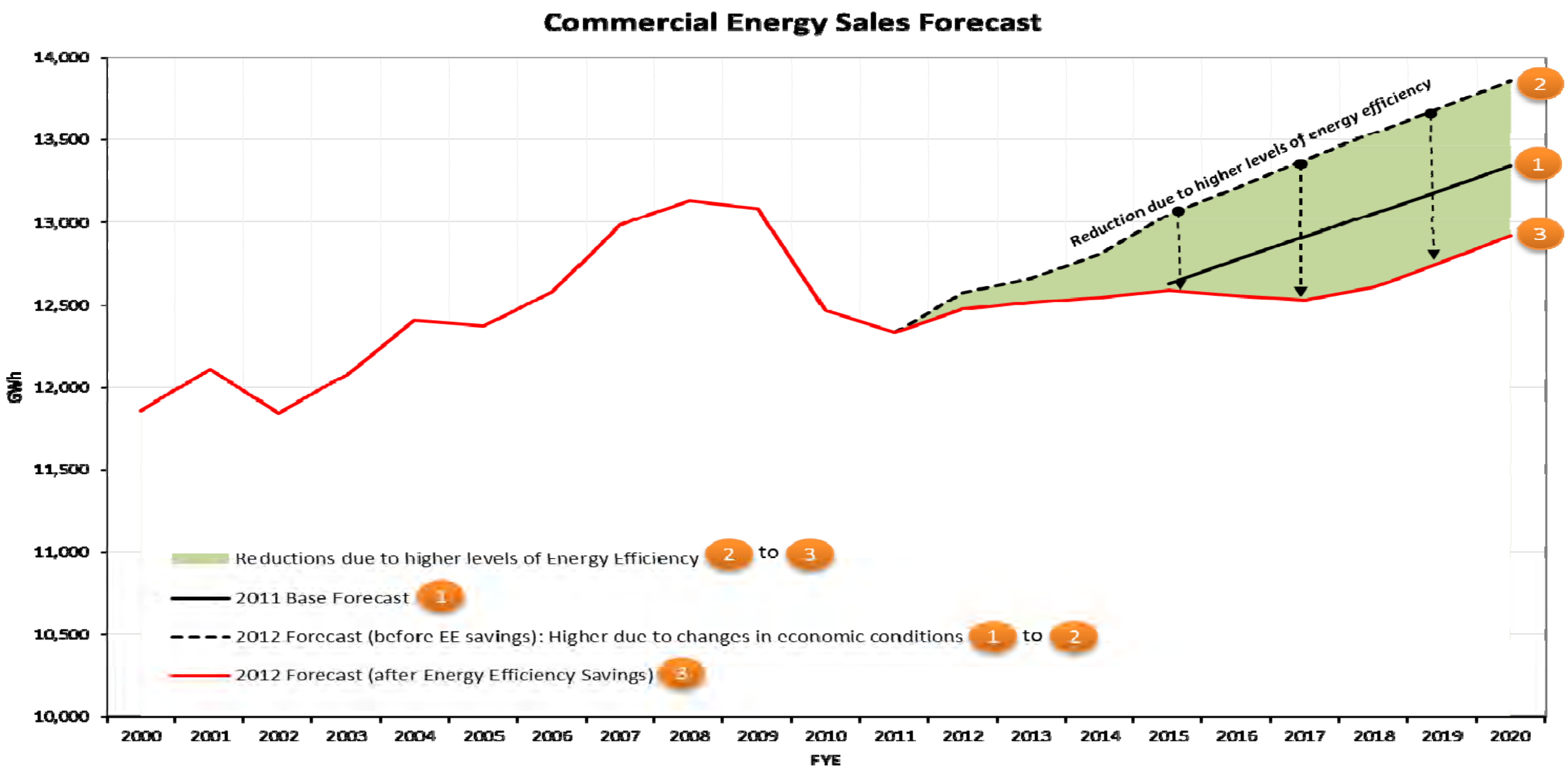
- ✓ Recovery ends and expansion begins in 2012.
- ✓ 1% growth - Below historical mean growth.



Commercial Energy Sales

Components of Change

- ✓ Service employment forecast slightly higher.
- ✓ Commercial construction activity down but positive absorption.

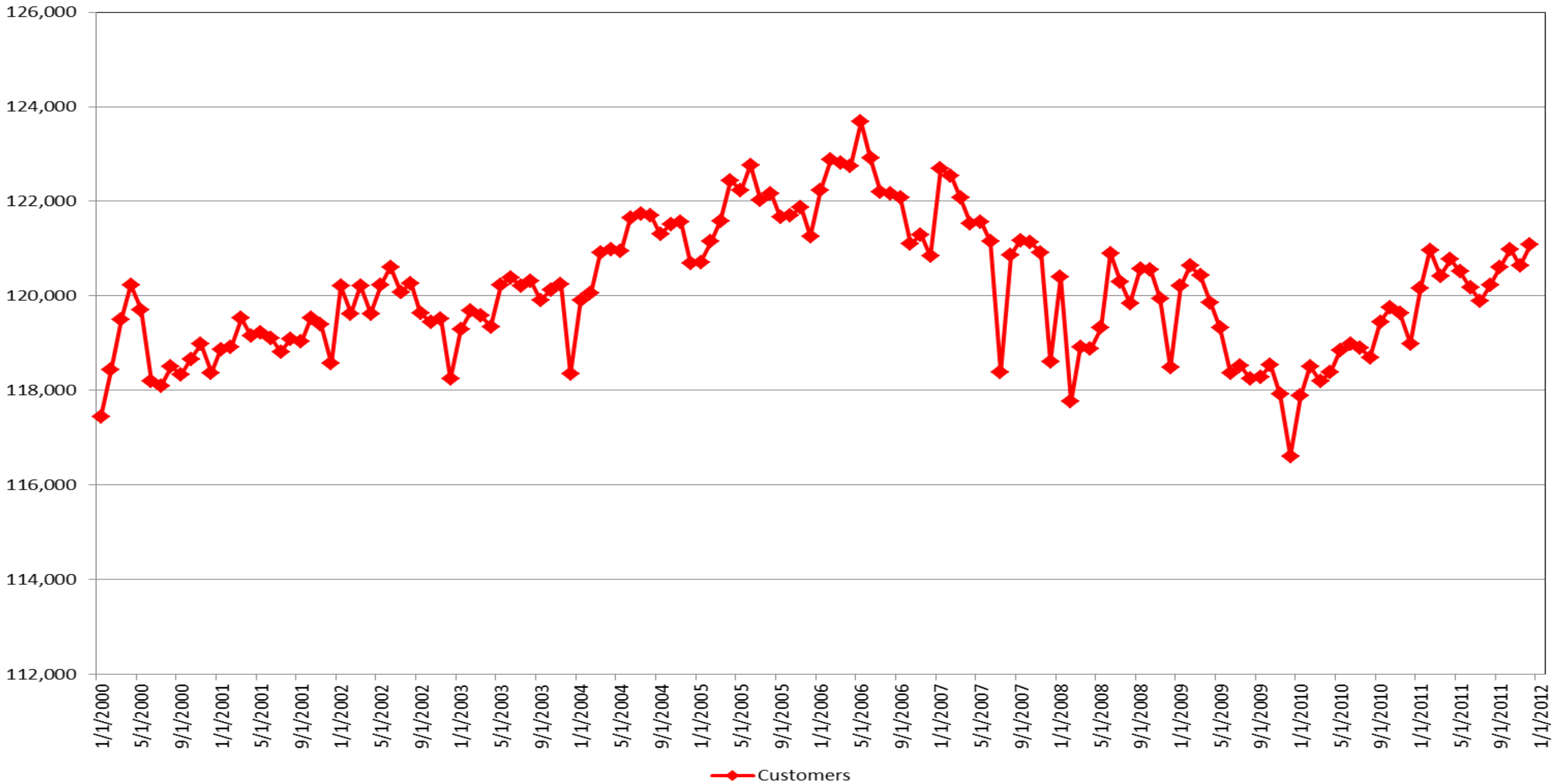


Commercial Energy Sales

Number of Commercial Customers

Recent Evidence

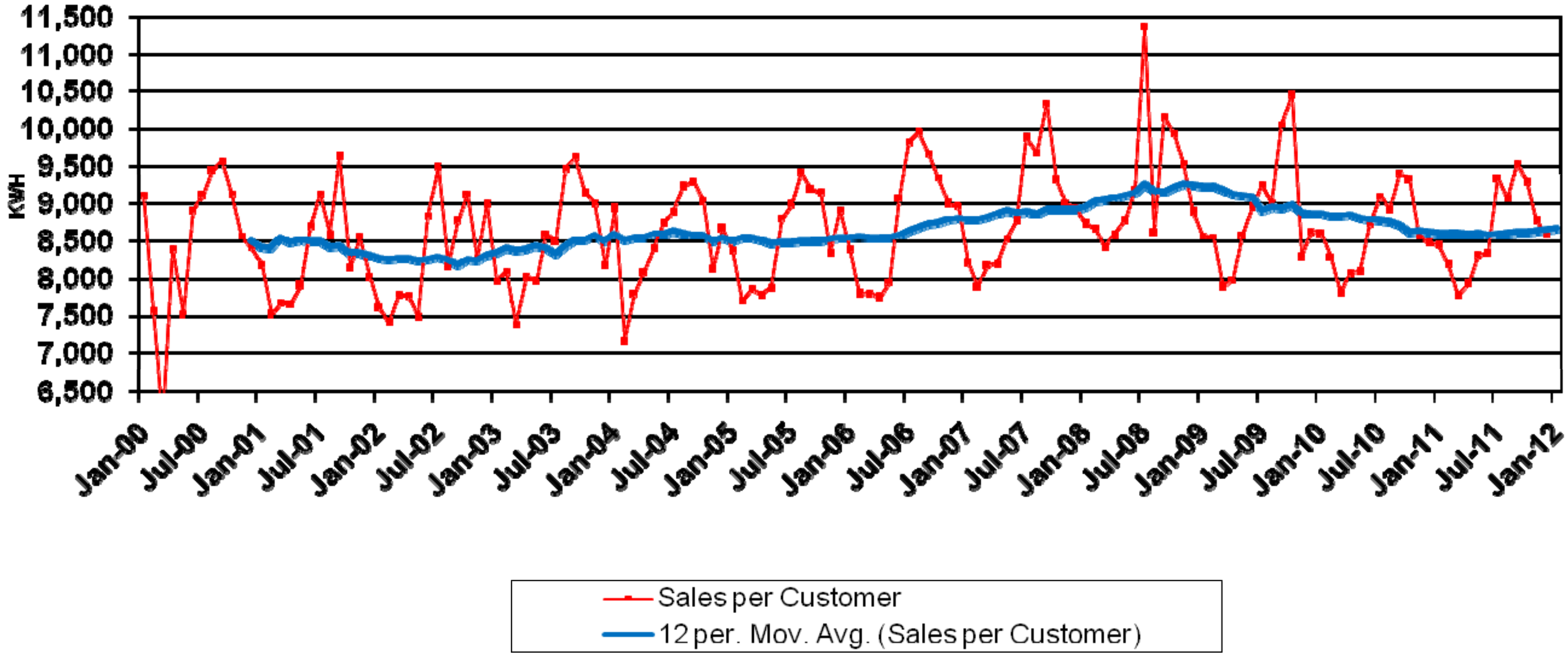
- ✓ There is a delay in bill collection. There are approximately 750 accounts past due, as result of the AMI implementation. LADWP is working to resolve this issue.



Commercial Energy Sales
Average Sales per Customer

Recent Evidence

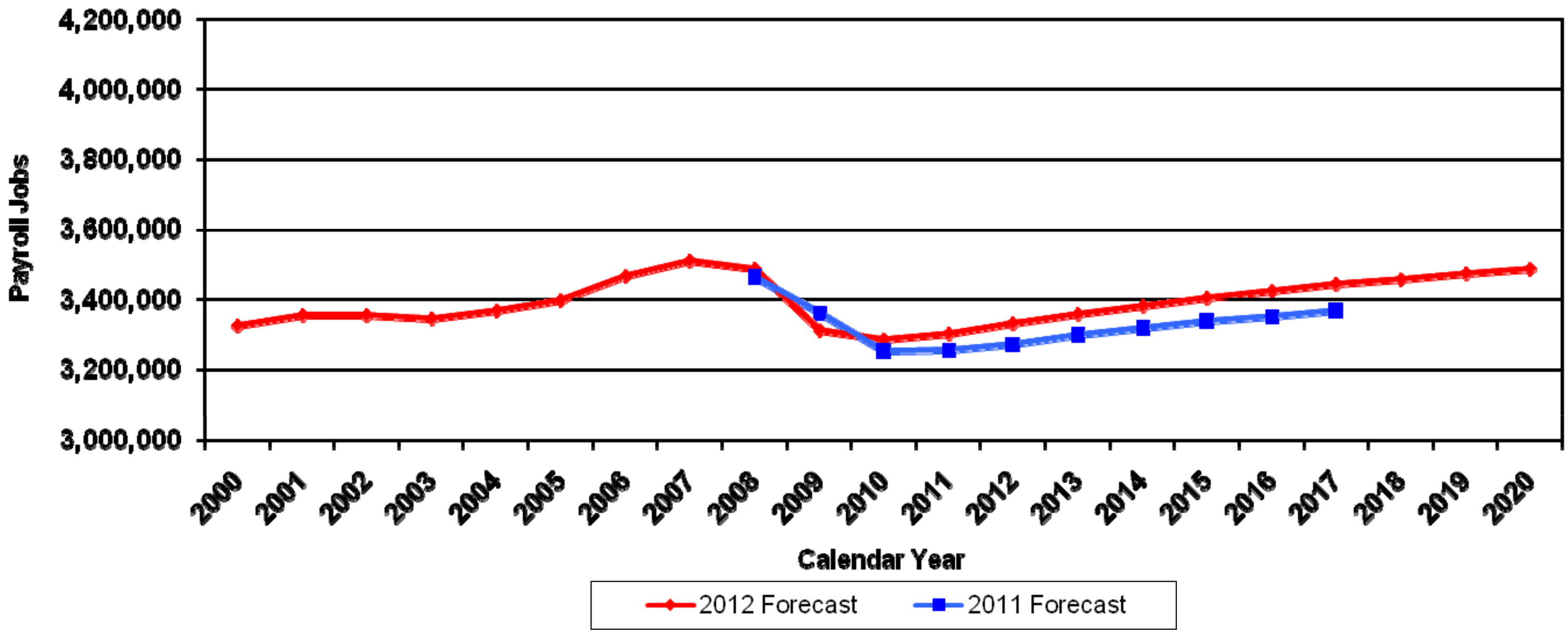
- ✓ Sales per customer per month peaked in July 2008 at 9265 KWH per month.
- ✓ Currently sales per customer per month are 8614 KWH.
- ✓ Weather normal sales per customer per month is 8690 KWH.



Commercial Energy Sales
Local Employment in Service Sector

LA County Commercial Services Employment

- ✓ Changing service delivery models – Internet and Big box retailers are two examples.
- ✓ Employment does not return to former high by 2020.

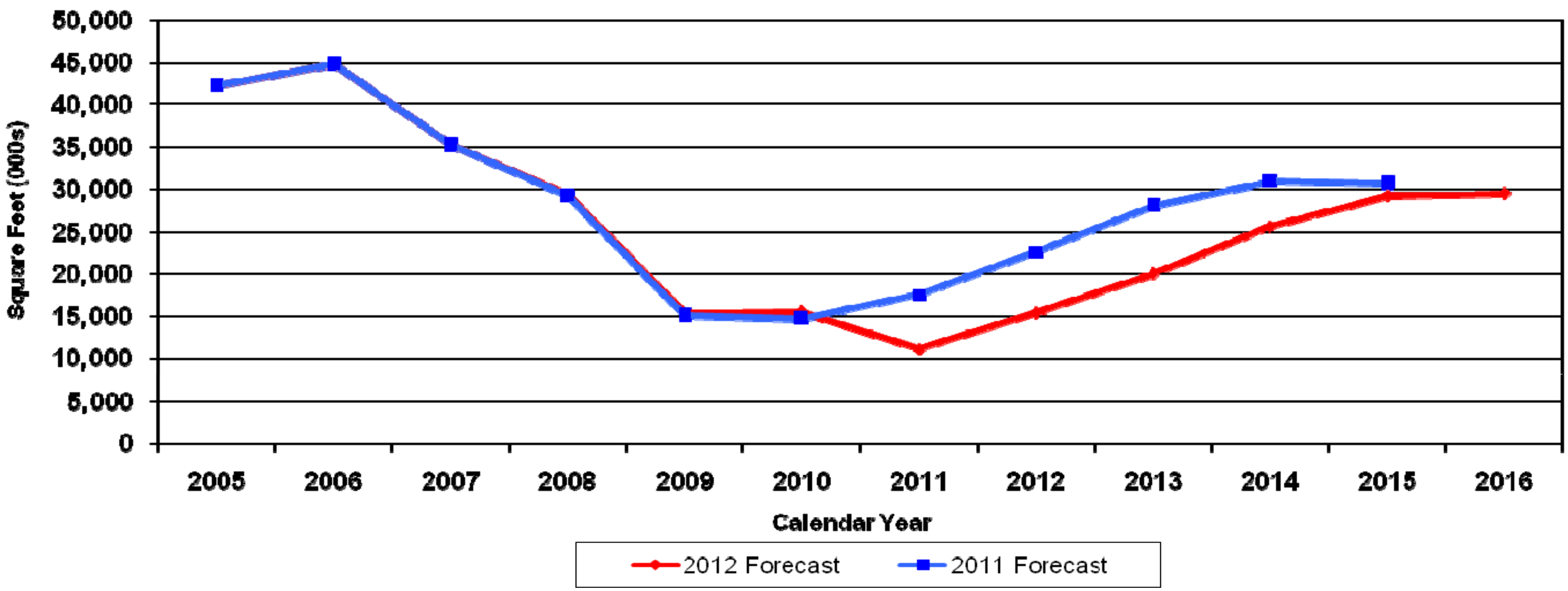


Commercial Energy Sales

McGraw-Hill Construction Forecast

Commercial Floorspace Additions

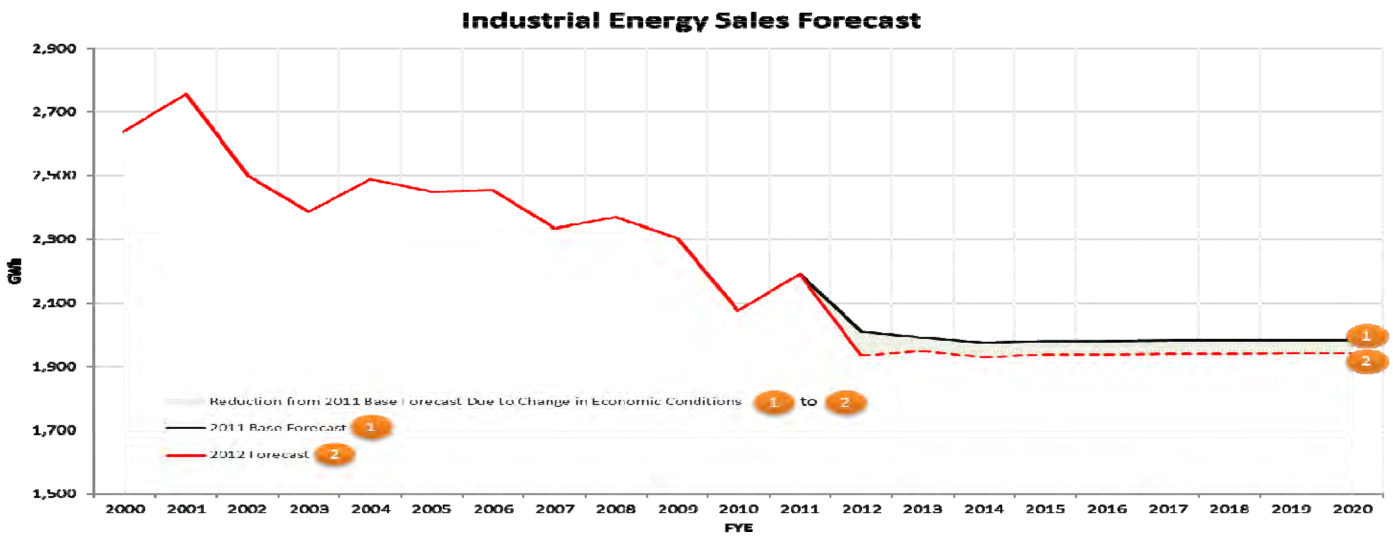
- ✓ Construction activity at historically low levels.
- ✓ Office vacancy rates in San Fernando Valley at 18 percent.
- ✓ New models for delivering commercial services require smaller physical presence.



Industrial Energy Sales

Components of Change

- ✓ Land use issue: Once industrial land is vacated, residential and commercial buildings tend to replace it. 3 to 4 percent vacancy rates in the industrial sector.
- ✓ Manufacturing that is staying tends to be high-value added manufacturing and process industries.
- ✓ Other manufacturing continues to move offshore or to the States with better business climate.
- ✓ No EE or rooftop solar in the Industrial Forecast. All EE and solar assigned to Residential, Commercial and Streetlight sectors.



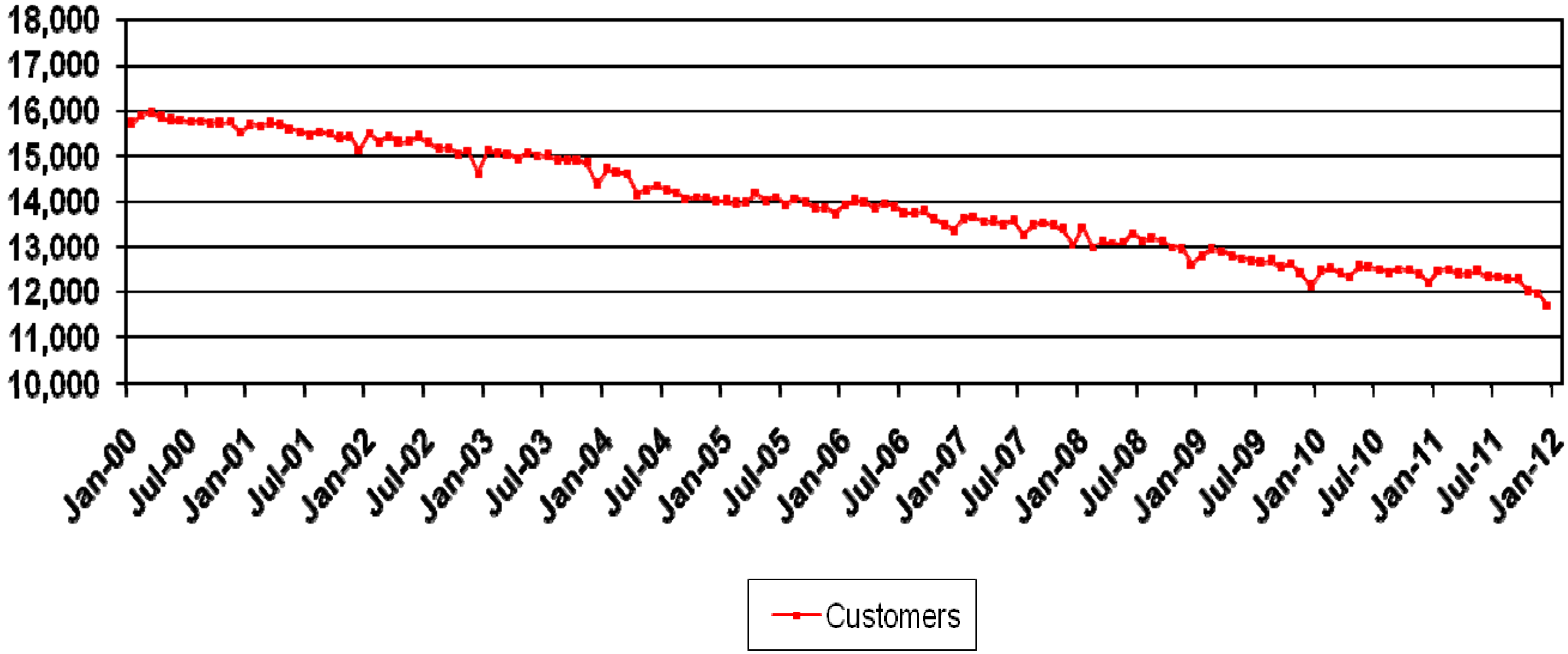
Industrial Energy Sales
Number of Industrial Customers

Recent Evidence

✓The number of Industrial customers is continually and relentlessly declining.

✓The decline began in the 1970s**.**

✓The forecast is for the heavy process industries to remain although no new heavy industry will be built. It is the light industry and assembly jobs that are disappearing.

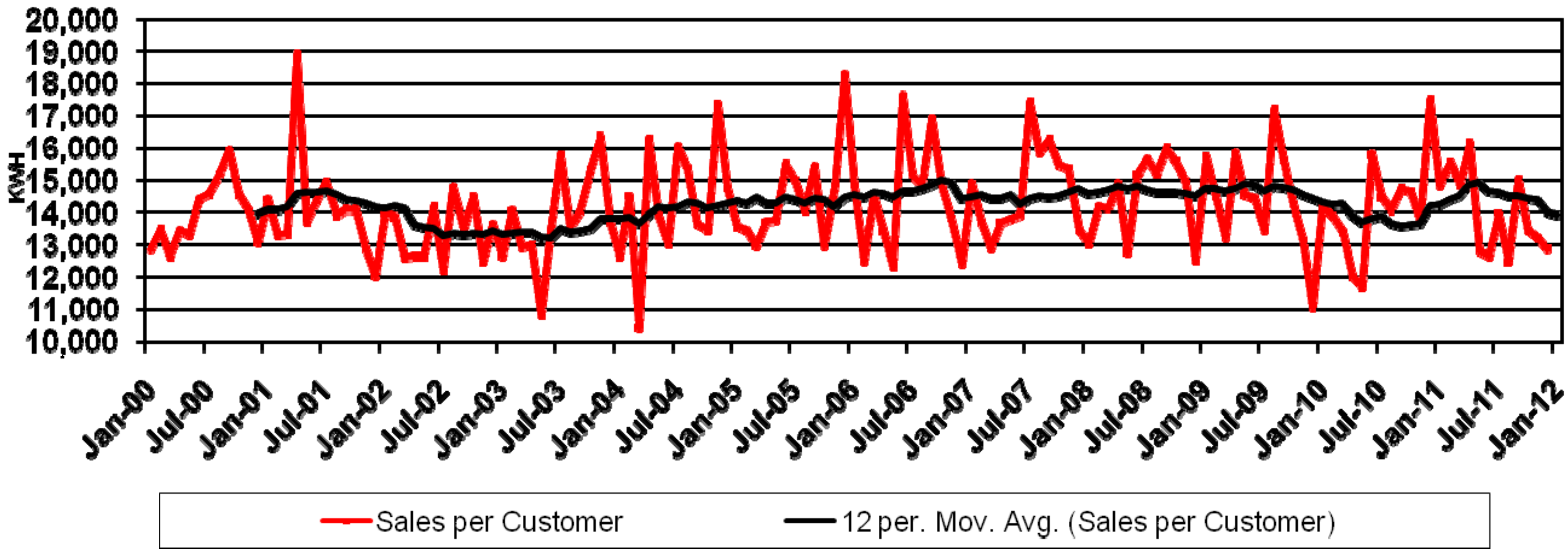


Industrial Energy Sales
Average Sales per Customer

Recent Evidence

✓Sales per customer per month peaked in October 2006 at 15026 KWH per month. High consumption partially attributed to a large self-generation unit being off-line at a refinery.

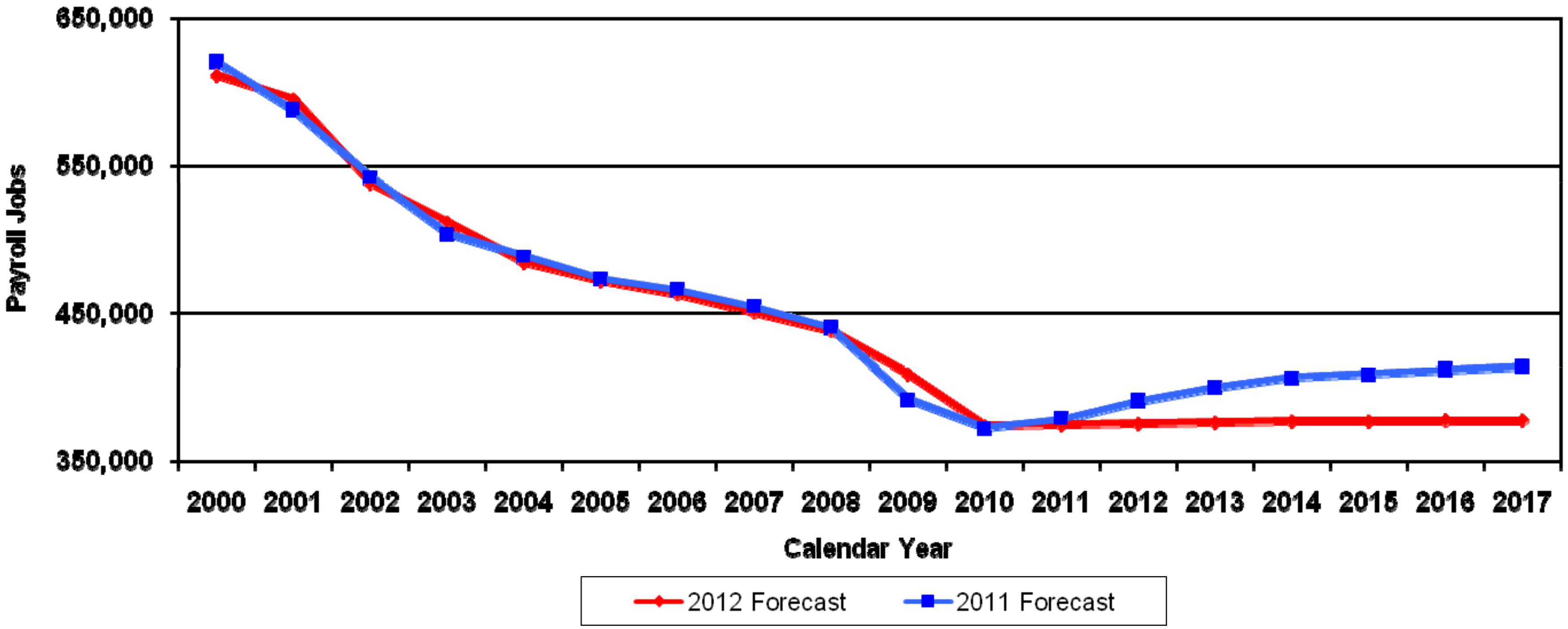
✓Currently sales per customer per month are 14000 KWH.



Industrial Energy Sales
Local Manufacturing Employment

LA County Manufacturing Employment

✓Future employment forecast is flat. If Los Angeles continues to lose manufacturing jobs then there will be a mismatch with the education level of the population and available high paying jobs. It could lead to significant population out-migration.

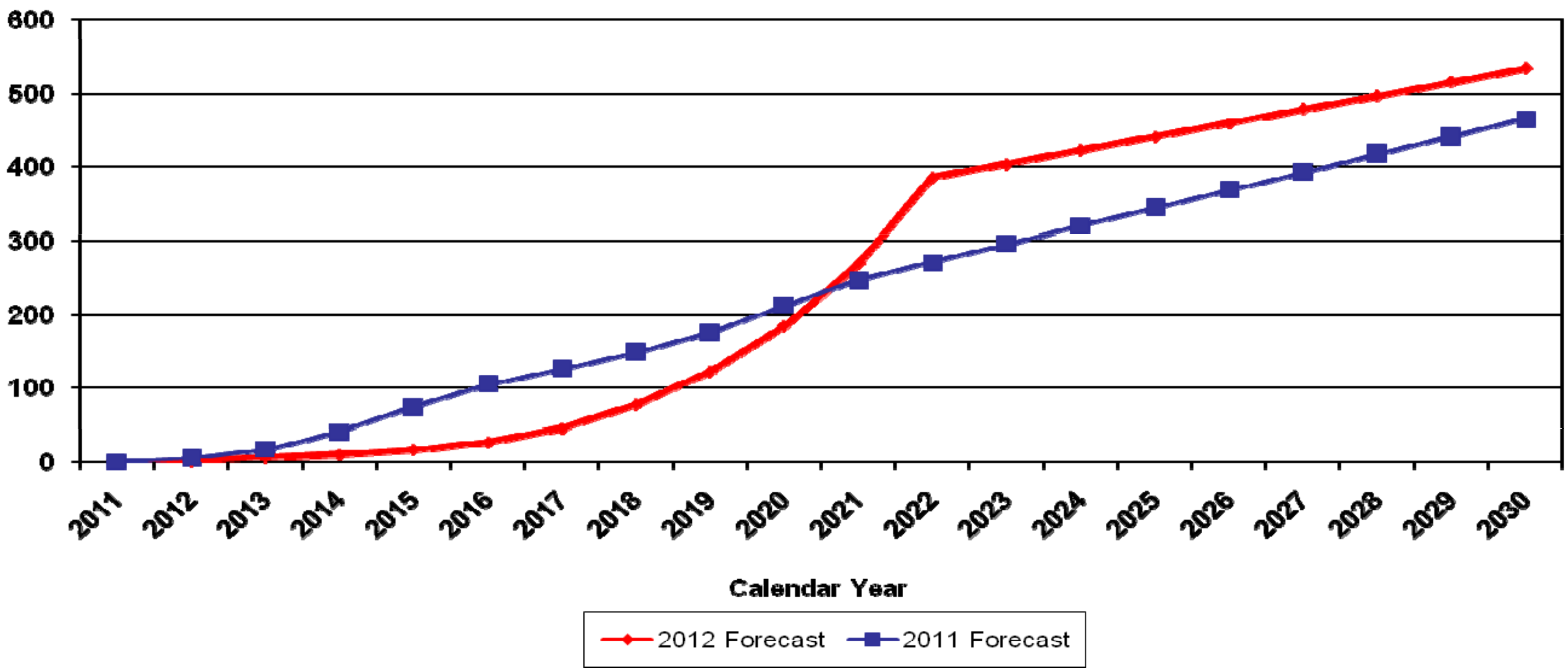


Electric Vehicle Sales

Load Growth

✓2012 forecast developed by the Plug-in Electric Vehicle Collaborative.

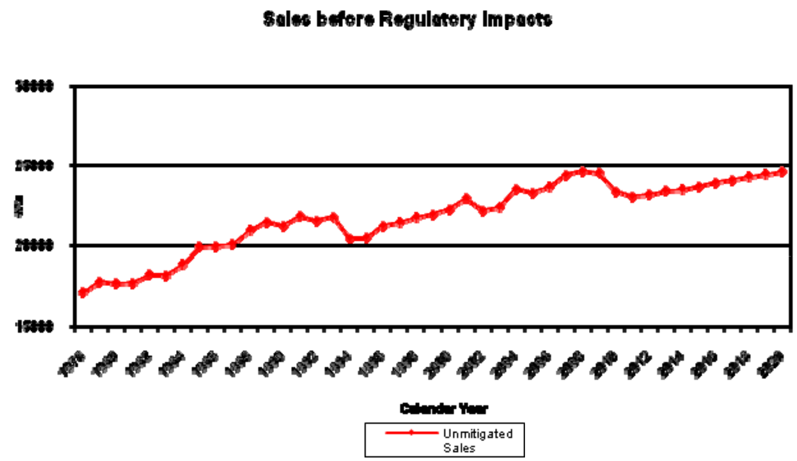
✓Also adopted by California Energy Commission



Plausibility

- Comparing unmitigated 2012 Sales Forecast to historical sales.
  - Unmitigated means forecasting sales based on economics alone before the impacts of environmental programs are considered.
  - Forecasted sales decline from 2008 to 2011 is largest in the past 30 years but smaller in scale.
  - No growth from economic factors in the next ten years. Next decade similar to what occurred in the 1990s before additional regulation.
  - LA is a mature economy.

Peak-to-Through Analysis		
Years	GWH Decline	Percent Decline
2008-2011	1,564	6.4%
1992-1994	1,421	7.0%
2000-2002	572	2.6%
1979-1980	322	1.8%
1981-1982	145	0.8%



This page is intentionally left blank

B

[redacted]

This page is intentionally left blank

NERC Reliability Criteria (TPL-001, TPL-002, TPL-003, TPL-004)

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 [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 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]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] 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): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 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 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ 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) An objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. Furthermore, in limited circumstances Firm Demand may need to be interrupted to address BES performance requirements. When interruption of Firm Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the use of Demand interruption are documented, including alternatives evaluated; and where the Demand interruption is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.

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.

C

[redacted]

Los Angeles Department of Water & Power

2011 Ten-Year Transmission Assessment

APPROVED BY:

ARAM BENYAMIN

SENIOR ASSISTANT GENERAL MANAGER

POWER SYSTEM

RANDY S. HOWARD

DIRECTOR

POWER SYSTEM PLANNING & DEVELOPMENT

MOHAMMED J. BESHIR

ASSISTANT DIRECTOR

POWER SYSTEM PLANNING & DEVELOPMENT

October 2011

Transmission Planning and Studies

Power System Planning & Development

Los Angeles Department of Water & Power

October 2011

2011 Ten-Year Transmission Assessment

Transmission Planning & Studies

Power System Planning & Development

Table of Contents

Appendices

APPENDIX A. NERC/WECC PLANNING STANDARDS

APPENDIX B. RECEIVING STATION LOADS

APPENDIX C. GENERATION SCHEDULE FOR LADWP-OWNED FACILITIES

APPENDIX D. TRANSMISSION LINE CAPACITIES

APPENDIX E. ONE-LINE DIAGRAMS

APPENDIX F. LIST OF CONTINGENCIES STUDIED

APPENDIX G. SWITCHING SEQUENCES FOR TRANSIENT AND POST-TRANSIENT

APPENDIX H. POWER FLOW RESULTS

APPENDIX I. TRANSIENT AND POST-TRANSIENT STABILITY RESULTS

APPENDIX J. RENEWABLE TRANSMISSION EXPANSION PROJECT

APPENDIX K. LONG-TERM TRANSMISSION PLAN

2011 Ten-Year Transmission Assessment

Executive Summary

The 2011 Ten-Year Transmission Assessment (2011 Assessment) covers years 2012 to 2021. At least one system (1-in-10 peak) condition is modeled for years 2012 through 2021.

the Los Angeles Department of Water and Power's (LADWP) 2011 Assessment is compliant with the four NERC Transmission Planning Standards:

1. TPL-001-0.1. System Performance Under Normal (No Contingency) Conditions (Category A)

2. TPL-002-0b. System Performance Following Loss of a Single Bulk Electric System Element (Category B)

3. TPL-003-0a. System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)

4. TPL-004-0. System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

The 2011 Assessment meets the following NERC Standard Measurements:

1. The Bulk Electric System (BES) shall be tested for steady-state, transient, dynamic, and voltage stability with all facilities in service, checking to find that all facilities are within their facility ratings and within their thermal, voltage, and stability limits.

2. The BES shall be tested for normal condition (Category A), checking to find that all facilities are within their facility ratings and within their thermal and voltage limits.

3. The BES shall be tested for transient, dynamic, and voltage stability following single contingencies (Category B) and multiple contingencies (Categories C and D), checking to find that all facilities are within their facility ratings and within their thermal, voltage, and stability limits.

With management's approval, this transmission assessment shall be a publicly available document and therefore made available to NERC and WECC. Identification of critical assets may be redacted for the general public.

This 2011 Assessment is based on WECC-approved case 2011HS2-OP which models anticipated heavy summer conditions with heavy flows from the Pacific Northwest to California and moderate flows elsewhere.

LADWP system loads for each study year are shown in Table 3 and are modeled according to the LADWP Financial Services Organization's Demand Forecast dated February 18, 2011. System studies were conducted consisting of steady state load flow analysis, transient stability analysis, and post-transient voltage stability analysis after incorporating planned system improvements and expansions, and resource acquisitions.

This 2011 Assessment does not indicate any Interconnection Reliability Operating Limit conditions or any post-contingency stability limits in the next ten years.

Full analyses of all credible outages listed in Appendix F reveals the existing and planned system should be able to sustain every studied contingency except for the following:

(1) A simultaneous (N-2) outage of Rinaldi-Tarzana 230kV Lines 1 & 2 as early as Summer 2012 would overload the terminal equipment on Northridge-Tarzana 230kV Line 1

(2) A simultaneous (N-2) outage of the Tarzana-Olympic 230kV Line 1 & the Tarzana-Olympic 138kV Line 1 during a summer heat storm would likely overload Scattergood-Olympic 230kV Line 2 until Scattergood-Olympic 230kV Line 1 is placed in service in 2014.

(3) A simultaneous (N-2) outage of Rinaldi-Tarzana 230kV Lines 1 & 2 during a summer heat storm would overload likely Scattergood-Olympic 230kV Line 2 until Scattergood-Olympic Line 1 is placed in service in 2014

(4) A simultaneous (extreme event) outage of three elements Rinaldi-Tarzana 230kV Lines 1& 2 and Northridge-Tarzana 230 kV Line 1) during a summer heat storm in 2014 would cause local low voltages at RS-U (Tarzana) and RS-T (Canoga)

(5) Planned solar projects between Inyo substation and Cottonwood tap would cause severe low voltage violations at Cottonwood as early as Summer 2020

(6) A single (N-1) outage of Haskell Canyon-Rinaldi 230 kV Line may overload the Haskell Canyon-Sylmar 230 kV Line as early as.Summer 2020

To mitigate these overloads, the following corrective actions are recommended. These measures will satisfy the applicable NERC planning standards for contingency or post-contingency system performance [a] :

(1) During the 2012 Summer Peak, continue using a selective load-shedding program at RS-U (Tarzana) to relieve the overload on the Northridge-Tarzana 230kV Line 1 during a double contingency outage of Rinaldi-Tarzana 230kV Lines 1 & 2. The load-shedding will be needed until the ampacity-limited terminal equipment (circuit breakers and disconnects) on the Northridge-Tarzana 230kV Line 1 are changed out in 2013.

The following three recommendations all utilize load shedding as an interim measure until the new Scattergood-Olympic 230 kV Line 1 is put in-service in June 2015:

(2) Through 2014, implement a selective load-shedding program at RS-K (Olympic) to relieve the overload on Scattergood-Olympic 230kV Line 2 during a double contingency outage of Tarzana-Olympic 230kV Line 1 and the Tarzana-Olympic 138kV Line 1.

(3) Through 2014, implement a selective load-shedding program at RS-U (Tarzana) and RS-K (Olympic) to relieve the overload on Scattergood-Olympic 230kV Line 2 during a double contingency outage of Rinaldi-Tarzana 230kV Lines 1 & 2.

[a] NERC TPL-002-0b for N-1 (Category B) , NERC TPL-003-0a for N-2 (Category C)

(4) Starting with Summer 2014, implement a selective under-voltage load-shedding program at RS-T to mitigate local low voltages at RS-U (Tarzana) and RS-T (Canoga) for the simultaneous outage of Rinaldi-Tarzana 230kV Lines 1& 2 and Northridge-Tarzana 230 kV Line 1. This 3-line outage is considered an extreme event.

(5) Before Summer 2020, resolve the low voltage violation at Cottonwood tap by constructing a new Cottonwood 230 kV substation and adding a new 100 MVAR capacitor bank.

(6) Before Summer 2020, resolve overloads on the Haskell Canyon-Sylmar 230 kV Line during a loss of the Haskell Canyon-Rinaldi 230 kV Line 1 by completing two actions:

- Relocate the 230/115 kV Banks from Olive Switching Station to Haskell Canyon Switching Station.

- Replace the existing twin 115 kV circuits between Haskell Canyon Switching Station and Olive Switching Station with a single new 230 kV circuit along existing 115 kV right-of-way. Extend the wire from Olive Switching Station to Sylmar Switching Station using the vacant position on the existing towers

Table 1 summarizes the findings and recommendations of the 2011 Assessment.

Table 1. FINDINGS AND RECOMMENDATIONS

Rec. No.	Year	Outage(s)	Reliability Category	Overloaded Line or System Violation	Recommendation
1	Summer Peak 2012	Rinaldi-Tarzana 230kV Lines 1 & 2	C (TPL-003-0a)	Terminal equipment on Northridge-Tarzana 230kV Line 1	Selectively shed load at RS-U (Tarzana) (~40 MW) for short term. Upgrade circuit breakers and disconnects to higher rating.
2	Summer Peak 2012 Through Summer Peak 2014	Tarzana-Olympic 230kV Line 1 & Tarzana-Olympic 138kV Line 1	C (TPL-003-0a)	Scattergood-Olympic 230kV Line 2	Selectively shed load at RS-K (Olympic) (~200 MW) and RS-U (~90 MW) for short term. Add new Scattergood-Olympic 230 kV Line 1 for long term.
3	Summer Peak 2012 Through Summer Peak 2014	Rinaldi-Tarzana 230kV Lines 1& 2	C (TPL-003-0a)	Scattergood-Olympic 230kV Line 2	Selectively shed load at RS-K (Olympic) (~200 MW) and RS-U (~90 MW) for short term. Add new Scattergood-Olympic 230 kV Line 1 for long term.
4	Summer Peak 2014 Onward	Rinaldi-Tarzana 230kV Lines 1& 2 and Northridge-Tarzana 230 kV Line 1	D (TPL-004-0)	Local voltage collapse	Suggested under-voltage load shedding program in RS-T.
5	Summer 2020	No Outage	A (TPL-001-0.1)	Low voltage violation at Cottonwood tap due to the addition of the planned solar projects	Construct a new Cottonwood 230 kV substation with a new 100 MVAR capacitor bank.
6	Summer Peak 2020	Haskell Canyon-Rinaldi 230 kV Line 1	B (TPL-002-0b)	Haskell Canyon-Sylmar 230 kV Line 1	Two actions are needed: • Relocate the 230/115 kV Banks from Olive Switching Station to Haskell Canyon Switching Station. • Replace the existing twin 115 kV circuits between Haskell Canyon Switching Station and Olive Switching Station with a single new 230 kV circuit along existing 115 kV right-of-way. Extend the wire from Olive Switching Station to Sylmar Switching Station using the vacant position on the existing towers.

Introduction

The City of Los Angeles' (City) transmission system consists of high voltage (above 500kV) alternating current (AC) and direct current (DC) transmission corridors and a 115kV-to-230kV in-basin network totaling more than 3,600 miles. Of those, high voltage AC and DC transmission lines alone account for 2,900 miles and provide over 5000MW of import capability. The City utilizes these resources to transport power from the Pacific Northwest, Utah, Arizona, Nevada, and within California to serve its customers and to wheel power for the Cities of Burbank and Glendale. In addition, the City's transmission system is interconnected with other utilities in the Western Electricity Coordinating Council (WECC) to coordinate and promote electric reliability throughout the Western United States. Thus, the importance of the security and adequacy of the City's transmission system extends beyond its physical boundaries. A drawing of LADWP's Power System is provided in Figure 1.

This 2011 Assessment covers years 2012 to 2021. At least one system (1-in-10 peak) condition is modeled for years 2012 through 2021.

As in previous years, the Los Angeles Department of Water and Power's (LADWP's) 2011 Ten-Year Transmission Assessment is fully NERC-compliant. Transmission Planning annually performs a ten-year transmission assessment, as required by NERC to:

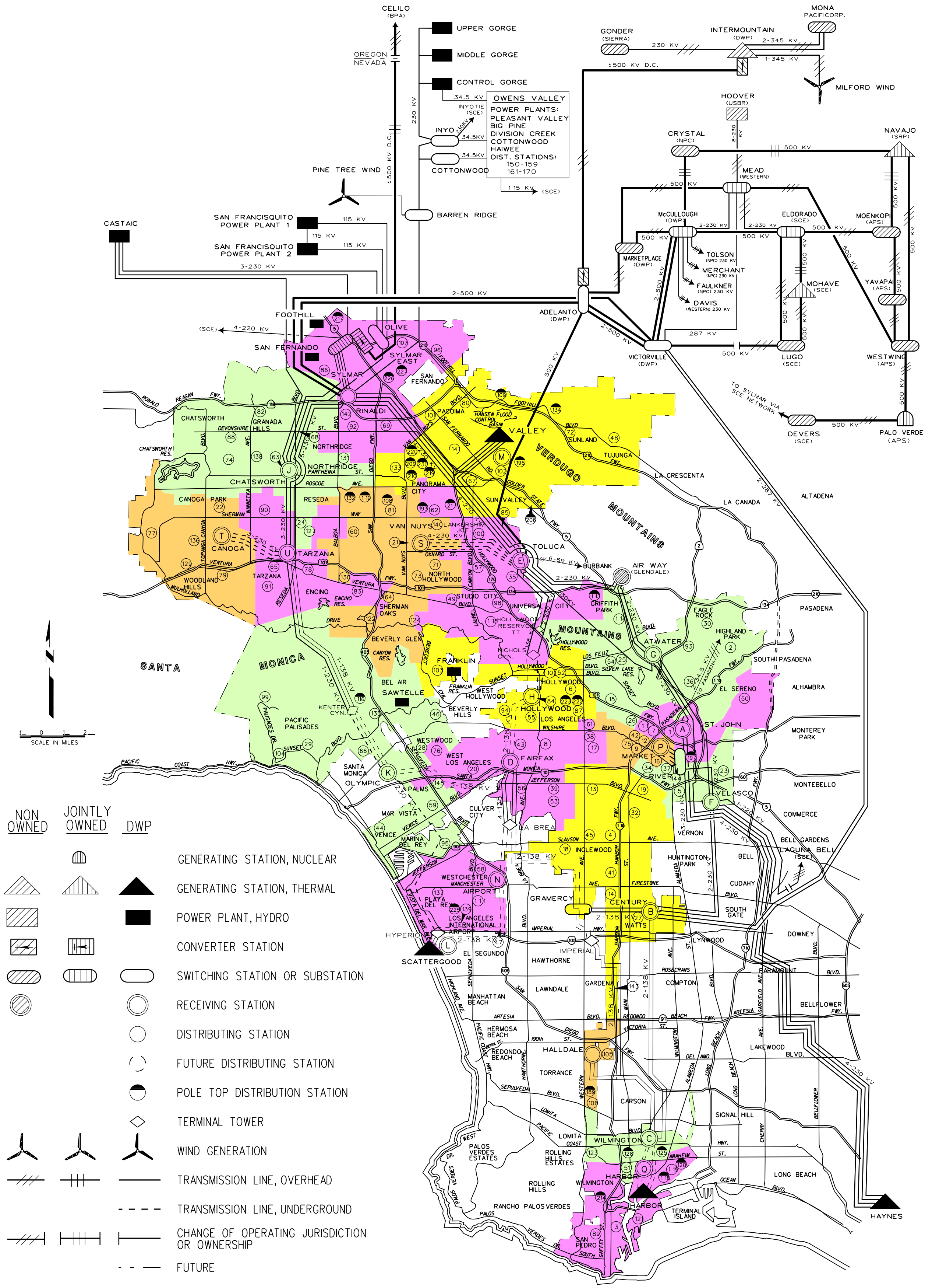
- ensure the City's electrical demand and energy requirements are met at all times under normal conditions (TPL-001-0.1);
- ensure the City's electrical system is able to withstand and respond to unanticipated system disturbances, losses of system components (TPL-002-0b and TPL-003-0a), and disturbances arising from switching operations;
- assess system performance following extreme events (TPL-004-0).

The specific transmission planning standards in effect at the time of this October 2011 assessment, and to which this assessment fully adheres, are:

1. TPL-001-0.1. System Performance Under Normal (No Contingency) Conditions (Category A)
2. TPL-002-0b. System Performance Following Loss of a Single Bulk Electric System Element (Category B)
3. TPL-003-0a. System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
4. TPL-004-0. System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

By responsibly addressing any concerns identified in this assessment before they become critical system limitations, LADWP should minimize system infrastructure costs, an important consideration in maintaining competitive electric rates.

POWER SYSTEM DIAGRAM



POWER SYSTEM PLANNING AND DEVELOPMENT
TRANSMISSION PLANNING GROUP

OES-LCM67
JULY 2010
REV. 16

Methodology

WECC Reference Case. Study cases were developed from the WECC-approved 2011HS2-OP case which models the expected power flows throughout the Western United States during heavy summer conditions, with heavy flows from the Pacific Northwest to California and moderate flows elsewhere.

Table 2 summarizes the power flows along major transmission corridors in the reference case that are relevant to this 2011 Assessment. These flows are scheduled above the projected LADWP's firm transfer levels to represent a reasonably stressed system.

TABLE 2. POWER FLOW ALONG THE MAJOR SOUTHERN CALIFORNIA TRANSMISION CORRIDORS IN THE REFERENCE BASE CASE (MW)

TRANSMISSION CORRIDOR	RATING (MW)	REFERENCE BASE CASE	
		Power Flow (MW)	% of Rating
Pacific DC Intertie (Path 65)	3100	2980	96%
Intermountain DC Line (Path 27)	2400	1748	73%
East-of-the-Colorado River (Path 49)	9300	4854	52%
West-of-the-Colorado River (Path 46)	10623	5693	54%
Victorville - Lugo 500kV Line 1 (Path 61)	2400	1108	46%
LADWP - SCE @ Sylmar (Path 41)	1600	-143	9%
Adelanto - Toluca 500kV Line 1	3800	901	64%
Adelanto - Rinaldi 500kV Line 1		582	
Victorville - Rinaldi 500kV Line 1		518	
Victorville - Century1 287kV Line 1		214	
Victorville - Century2 287kV Line 1		214	

Analysis. A minimum of one study case is developed from the 2011HS2-OP reference case for each study year, 2012 through 2021. Each study case models the LADWP system as it is likely to be configured on a 1-in-10 year peak summer day to capture the critical system conditions for each year.

Initially, power flow studies are conducted for each study case with all transmission facilities in-service (N-0) and operating normally. Disturbances are then simulated such that all single-transmission line or transformer outages (N-1) and all credible double-transmission line outages (N-2) are studied in turn. The results from these studies identify the transmission lines vulnerable to thermal overloads or significant voltage depression. The most severe of these scenarios are further studied for post-transient stability and reactive margins.

As a summer-peaking system, LADWP plans its outages at cooler times of the year. Therefore, planned outages as initial conditions are not modeled in this 2011 Assessment.

Transient stability is investigated for line outages of critical transmission paths to identify any inter-regional impact and to ensure system adequacy and security. Control devices such as HVDC controls, SVC controls and all other controls are included in the WECC dynamic database. Protective systems such as Under-frequency Load Shedding are also included in the WECC dynamic database, whereas relevant remedial action schemes are listed in the switching sequence files which drive the dynamic simulation.

Where study results show that transmission paths are constrained, overloaded, or unstable, recommendations to mitigate or alleviate the problems are provided.

Criteria. Annual transmission assessments are performed to comply with NERC/WECC Planning Standards (Appendix A) and to fulfill WECC's requirement that each utility independently performs such a reliability assessment and demonstrates compliance with the NERC/WECC standards.

Power Flow. In addition to the NERC and WECC requirements, LADWP has established performance standards for its in-basin electric system as follows:

1. With all transmission system components in service (N-0), the in-basin electric system shall not experience the following:
    a. Interruption of load
    b. Bus voltage less than 0.99 pu
    c. With the worst-case generating unit off-line, operation of a transmission system component at a level in excess of its normal rating.
2. A Single Contingency (N-1) shall not result in any of the following:
    a. Interruption of load
    b. Bus voltage less than 0.95 pu
    c. With the worst-case generating unit off-line, operation of a transmission system component at a level in excess of its emergency rating.

Transient and Post-Transient Stability. Transient and post-transient performance under the various contingencies described in Appendix G shall meet the following additional requirements:

Transient Stability:

1. All machines in the system shall remain in synchronism as demonstrated by their relative rotor angles
2. Induction motors shall be modeled at 20% of the total load across the WECC region

3. System stability shall be evaluated based on the damping of the relative rotor angles and the damping of the voltage magnitude swings

4. The transient voltage dip should be maintained above 0.80pu at Adelanto and Sylmar

Post-Transient Stability

1. All loads shall be modeled as constant MVA during the first few minutes following an outage or disturbance.

2. All voltages at distribution substations shall be restored to normal values by the transformer tap changers and other voltage control devices.

3. Generator MVAR limits shall be modeled as a single value for each generator since the reactive power capability curve will not be modeled in the program output.

4. No manual operator intervention is allowed to increase the generator MVAR flow.

5. Remedial actions such as generator dropping, load shedding and blocking of automatic generation control (AGC) shall not be considered for single contingencies.

6. Shunt capacitors (132 MVAR) at Adelanto and Marketplace shall be used if the post-transient voltage deviation exceeds 5% at those buses. Although modeled as shunt capacitors the actual devices are automatically controlled Static Var Compensators (SVCs).

7. Other assumptions:
   - Area Interchange: Disabled
   - Governor Blocking: Base load flag shall be used per WECC practice
   - DC Line Transformer Tap Automatic Adjustment: Enabled
   - Generator Voltage Control set to local except for Palo Verde, and selected Northwest generation
   - Phase Shifter Control: Disabled
   - Switched Shunt Devices: Disabled

Assumptions

LADWP Loads. One-in-ten year summer heat storms, as represented in the "2011 Retail Electric Sales and Demand Forecast" signed on February 18, 2011 are modeled each year in the study. This 2011 Assessment which uses gross 1-in-10 demand differs from the net 1-in-10 demand used in the 2010 Assessment. Gross Demand is the sum of Net Demand and Cogeneration. Table 3 tabulates the total gross bus load represented in the ten-year power flow.

Table 3. 2011 LADWP POWER FLOW BUS LOADS (MW)

Year	Net 1-in-10	Co-Generation	Gross 1-in-10	OV & Losses	Total Gross Bus Load
2012	6092	258	6350	536	5814
2013	6089	277	6366	546	5820
2014	6188	293	6481	552	5929
2015	6277	306	6583	558	6025
2016	6365	314	6679	566	6113
2017	6442	319	6761	575	6186
2018	6527	316	6843	584	6259
2019	6615	319	6934	593	6341
2020	6710	330	7040	602	6438
2021	6830	337	7167	611	6556

Receiving Station loads are scaled according to the "Receiving Station and Distributing Station Load Forecast – 2010 to 2019" distributed March 29, 2011. Loading at receiving station banks are generally developed with the power factors provided in the Receiving Station/Distribution Station Forecast, but with some modification to match available historical peak load data. Table 4 lists the forecasted real power loads at the receiving station level. Appendix B lists the coincidental peak real and reactive power loads at the receiving stations.

Table 4. RECEIVING STATION (RS) PEAK LOADS (MW)

Service Area	Receiving Station	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Central	Airport	214	214	216	216	219	225	228	229	236	241
	Atwater	320	322	331	330	335	340	345	349	355	361
	Century	307	307	316	322	326	330	333	340	345	352
	Fairfax	403	403	407	415	417	423	425	429	435	443
	Hollywood	401	405	412	420	431	435	441	447	454	462
	Market (River)	375	372	376	381	383	385	389	390	396	404
	Olympic	421	420	434	440	447	454	460	466	473	482
	Scattergood	27	27	28	28	28	28	28	28	28	29
	St. John	228	227	232	235	239	240	243	245	249	254
	Velasco	227	229	231	234	237	238	243	245	248	253
	Total Central Load	**2923**	**2926**	**2982**	**3024**	**3068**	**3101**	**3136**	**3171**	**3219**	**3281**
Southern	Halldale	49	49	50	51	51	53	53	53	54	55
	Harbor	206	206	208	211	213	215	217	220	223	227
	Wilmington	166	166	170	172	173	176	176	178	181	185
	Total Southern Load	**421**	**421**	**428**	**434**	**437**	**444**	**446**	**451**	**458**	**467**
Valley	Canoga	375	374	380	386	390	382	385	388	394	402
	Northridge	546	542	553	564	572	593	600	609	618	628
	Rinaldi	291	297	303	309	317	322	327	332	337	343
	Tarzana	347	348	355	363	368	371	377	384	390	397
	Toluca	404	405	406	413	421	425	432	439	446	454
	Valley	315	316	323	327	327	335	340	345	350	356
	Van Nuys	424	426	438	446	457	461	467	475	483	491
	Total Valley Load	**2702**	**2708**	**2758**	**2808**	**2852**	**2889**	**2928**	**2972**	**3018**	**3071**
Total Receiving Station Load		**6046**	**6055**	**6168**	**6266**	**6357**	**6434**	**6510**	**6594**	**6695**	**6819**
Diversity Factor		1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04
Total Coincidental Receiving Station Load		**5813**	**5822**	**5931**	**6025**	**6113**	**6187**	**6260**	**6340**	**6438**	**6557**
Owens Valley Load & Transmission Losses		536	546	552	558	566	575	584	593	602	611
1-in 10 Peak Load Forecast[b]		**6349**	**6368**	**6483**	**6583**	**6679**	**6762**	**6844**	**6933**	**7040**	**7168**

Burbank and Glendale Loads. One-in-ten peak load forecasts of the cities of Burbank and Glendale modeled in each study case.

[b] Forecast estimates customer generation of 258MW in 2011 increase to 337 MW in 2021

Comparison of Demand forecast - LADWP Integrated Resource Plan vs. Assessment

The Net 1-in-10 Demand is the key to match this 2011 Assessment with the LADWP's Integrated Resource Plan (IRP). Both plans are based on the Net 1-in-10 from the "2011 Retail Electric Sales and Demand Forecast", however, if a new official demand forecast is released after this 2011 Assessment, the IRP may have the benefit of that forecast. One likely adjustment is the contribution from additional Energy Efficiency programs that reduce forecast demand. The potential for referencing different forecasts should be eliminated in future years as efforts are being made to release annual transmission assessments and IRPs concurrently.

Infrastructure Improvements and Expansion. Table 5 lists the infrastructure improvements, expansion projects, and resource re-powering captured in this 2011 Ten-Year Transmission Assessment.

Table 5. PLANNED SYSTEM ENHANCEMENTS

System Enhancements	In-Service Date	Initial Model Year
Northridge – Tarzana 230 kV Line Upgrade	July 2012, delayed breaker installation will limit rating	2012
Castaic Power Plant Modernization	January 2013	2013
Haynes Generating Station Re-powering Phase 2	December 2013	2014
Scattergood-Olympic 230KV Line 1	June 2015	2015
RS-C Bypass	March 2015	2015
Barren Ridge-Haskell 230kV Lines 2 & 3 (new) (*)	June 2015	2015
Scattergood Generating Unit 3 Re-powering		
Barren Ridge-Rinaldi 230kV Line 1 (upgrade) (*)	June 2016	2016

(*) The new Barren Ridge-Haskell 230kV Lines and the upgraded Barren Ridge-Rinaldi 230kV Line are part of the Renewable Transmission Expansion Project as illustrated in Appendix J

Table 6 lists Renewable generation additions to the LADWP Balancing Authority area that were modeled in the 2011 Assessment.

Table 6. RENEWABLE GENERATION ADDITIONS (MW)

Project	Capacity MW	In-Service Date	Initial Model Year
Pine Tree Solar	8.5	Sep-2012	2012
Solar 11	10	Jun-2012	2012
Solar 2	250	May-2014	2014
Solar 10	50	Dec-2013	2014
Solar 10	50	Jul-2014	2014
Solar 10	50	Jul-2015	2015
Solar 10	50	Aug-2016	2016
Solar 17	25	Jul-2016	2016
Solar 17	25	Jul-2017	2017
Wind 10	150	Dec-2017	2018
Solar 17	25	Jul-2018	2018
Solar 17	25	Jul-2019	2019

Generation. LADWP's existing and future resources are capable of producing up to 5902 MW internally and 2747 MW externally. Table 7 shows how LADWP's resources are dispatched in this study; unit commitments are provided in Appendix C.

TABLE 7. LADWP's GENERATION MIX (MW)

Resource Type	Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Pumped Storage	1540	110	117	118	97	82	147	160	190	1068	1195
Natural Gas	3538	1942	1942	1842	1842	1882	1882	1842	1882	2777	2777
Wind	285	82	82	82	82	82	82	172	172	172	172
Solar	318.5	18	18	271	376	451	476	501	526	526	526
Hydroelectric	220.5	160	160	160	160	160	160	160	160	160	160
Internal Generation	***5902***	***2311***	***2319***	***2472***	***2557***	***2656***	***2747***	***2835***	***2930***	***4703***	***4830***
% of Total Generation	68%	48%	48%	50%	51%	52%	52%	53%	59%	70%	71%
Hydroelectric	491	410	410	410	410	410	410	410	410	410	410
Wind	300	120	120	120	120	120	120	120	120	120	120
Coal	1569	1569	1569	1569	1569	1569	1569	1569	1092	1092	1092
Nuclear	387	387	387	387	387	387	387	387	387	387	387
External Generation(*)	***2747***	***2486***	***2486***	***2486***	***2486***	***2486***	***2486***	***2486***	***2009***	***2009***	***2009***
% of Total Generation	32%	52%	52%	50%	49%	48%	48%	47%	41%	30%	29%
Total Generation	**8649**	**4797**	**4805**	**4958**	**5043**	**5142**	**5233**	**5321**	**4939**	**6712**	**6839**

(*) *External Generation represents projected firm transfer for each of the ten years*

This 2011 Assessment shows that sufficient capacity is available to meet the Renewable Portfolio Standard target of 33% provided that certain renewable resources are imported using (a) transmission from the retired Navajo coal generation facility, (b) the Pacific DC Intertie, and (c) 98 MW of roof top solar goals in 2020[c]. Appendix C shows the breakdown of renewable energy resources represented in the 2020 Heavy Summer study case with LADWP reaching its 33% RPS target.

Transmission. LADWP's extensive transmission system of more than 3,000 circuit miles reaching beyond its neighboring states facilitates access to low cost power purchases and LADWP's external generation. As Table 8 shows, around 60 percent of LADWP's power needs are served by heavily leveraging these transmission assets. Over the next ten years, additions of approximately 100 circuit-miles of transmission will increase LADWP's access to renewable energy intrastate.

Table 8. ELECTRIC SUPPLY-DEMAND BALANCE (MW)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
LADWP Receiving Station Load	5813	5822	5931	6025	6113	6187	6260	6340	6438	6557
System Losses	536	546	552	558	566	575	584	593	602	611
Total Power Requirement	**6349**	**6368**	**6483**	**6583**	**6679**	**6762**	**6844**	**6933**	**7040**	**7168**
Internal Generation	***2311***	***2319***	***2472***	***2557***	***2656***	***2747***	***2835***	***2930***	***4703***	***4830***
% Power Requirement	*36%*	*36%*	*38%*	*39%*	*40%*	*41%*	*41%*	*42%*	*67%*	*67%*
External Generation & Purchases	***4038***	***4049***	***4011***	***4026***	***4023***	***4015***	***4009***	***4003***	***2337***	***2338***
% Power Requirement	*64%*	*64%*	*62%*	*61%*	*60%*	*59%*	*59%*	*58%*	*33%*	*33%*

[c] The 10 Year Transmission Assessment takes a snap-shot of the system at the hours of the highest stress on the electrical system. This peak snapshot will likely have a lower than average renewable mix because thermal peaking units are required on peak hours. In contrast to thermal peaking units, renewable resources are used any hour they are available, all year long. Because the renewable target is the annual energy consumed, regardless what is seen in a single snap-shot, the actual resource mix could be substantially lower on the most stressed hours without preventing LADWP from meeting its 2020 RPS's goal.

Table 9 summarizes the power flows along LADWP's major transmission paths in this 2011 Ten-Year Transmission Assessment.

Table 9. FLOWS ALONG MAJOR TRANSMISSION CORRIDORS IN STUDY CASES (MW)

TRANSMISSION CORRIDOR	RATING (MW)	BASE CASE YEAR									
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Pacific DC Intertie (Path 65)	3100	2780	2780	2780	2780	2780	2780	2780	2780	2400	2400
Intermountain DC Line (Path 27)	2400	1748	1748	1748	1748	1748	1748	1748	1748	2105	2105
East-of-the-Colorado River (Path 49)	9300	4860	4860	4860	4860	4861	4861	4860	4861	2093	2092
West-of-the-Colorado River (Path 46)	10623	5706	5706	5705	5706	5707	5707	5706	5707	2071	2071
Victorville - Lugo 500kV Line 1 (Path 61)	2400	1064	1064	1058	1045	1033	1030	1027	1026	1268	1263
LADWP - SCE @ Sylmar (Path 41)	1600	-155	-155	-145	-135	-145	-141	-129	-137	-20	-18
Adelanto - Toluca 500kV Line 1		932	933	948	956	964	969	977	980	544	551
Adelanto - Rinaldi 500kV Line 1		614	614	600	603	605	601	595	593	164	160
Victorville - Rinaldi 500kV Line 1	3800	550	550	538	541	543	540	534	533	116	112
Victorville - Century1 287kV Line 1		199	199	206	209	210	212	215	215	127	131
Victorville - Century2 287kV Line 1		199	199	206	209	210	212	215	215	127	131

Assessment Results

- **(N-0) or No contingencies.** The LADWP system meets the performance requirements of Category A in all study cases except one. During a heat storm in 2020, the voltage may be unacceptably low at Cottonwood tap

- **(N-1) Contingencies.** Every LADWP transmission circuit underwent an (N-1) contingency to identify one potential problem: Haskell Canyon-Sylmar 230 kV Line 1.

. **Haskell Canyon-Sylmar 230kV Line Overloads**

Table 10 shows that projects to mitigate overloads on Haskell Canyon-Sylmar 230 kV Line 1 need to be completed by 2020.

Table 10. Overloads on Haskell Canyon-Sylmar from (N-1) Contingency

Single Outage	Overloaded Line	Loading	Study Year
Haskell Canyon-Rinaldi 230kV Line 1	Haskell Canyon –Sylmar 230kV Line 1	103%	2020

-

- **(N-2) Contingencies.** Performance criteria were not met with regard to (a) Scattergood-Olympic 230kV Line 2 overloads and (b) Northridge-Tarzana 230kV Line 1 terminal equipment (circuit breakers and disconnects) overloads.

Scattergood-Olympic 230kV Line Overloads

Table 11 shows that overloads on Scattergood-Olympic 230kv Line 2 are remedied by the new Scattergood-Olympic 230 kV Line 1 scheduled to be in service in June 2015.

Table 11. Overloads on Scattergood-Olympic from (N-2) Contingencies

Double Outage	Overloaded Component	Loading	Study Year
Rinaldi-Tarzana 230kV Lines 1 & 2	Scattergood-Olympic 230kV Line 2	116%	2012-14
Rinaldi-Tarzana 230kV Lines 1 & 2	Scattergood-Olympic 230kV Line 2	<90%	2015-21
Tarzana-Olympic 230kV Line 1 & Tarzana-Olympic 138kV Line 1	Scattergood-Olympic 230kV Line 2	128%-130%	2012-14
Tarzana-Olympic 230kV Line 1 & Tarzana-Olympic 138kV Line 1	Scattergood-Olympic 230kV Line 2	<90%	2015-21

Northridge-Tarzana 230kV Line Overloads

Table 12 shows Northridge-Tarzana 230kV Line 1 needs to be reinforced. Ignoring this work would likely overload the line during a double line outage of Rinaldi-Tarzana Lines 1 & 2 (230kV) during summer heat storms.

Table 12. Overloads on Northridge-Tarzana from (N-2) Contingencies

Double Outage	Overloaded Component	Loading	Study Year
Rinaldi-Tarzana 230kV Lines 1 & 2	Terminal equipment of Northridge-Tarzana 230kV Line 1 : 2 CB & 2 disconnects @ RS-J. 3 CB and 6 disconnects @RS-U	>2kA	2012
Rinaldi-Tarzana 230kV Lines 1 & 2	Northridge-Tarzana 230kV Line 1	<90%	2013-20

- **Extreme Events — Multiple Circuit Outages**

NERC maintains no specific requirements for utilities in their examination of system performance following extreme events, so different conditions can be studied from one year to the next. Further, there is no NERC or WECC requirement to plan corrective action for extreme events.

LADWP elects to study extreme events that are credible and potentially harmful to the BES. In this Assessment, the two extreme events studied involve the simultaneous loss of three lines strung on common towers. Two such triple-circuit tower losses were simulated for study year 2016.

Table 13 shows that the loss of a triple-circuit tower which consists of Toluca-Hollywood 230kV lines 1 & 3 and Toluca-Hollywood 138kV Line 2 would not result in any overloads or any voltage violations. However, the loss of a triple-circuit tower which carries Rinaldi-Tarzana 230kV Lines 1 and 2 and Northridge-Tarzana 230kV Line 1 would result in local under-voltage conditions at RS-U (Tarzana) and RS-T (Canoga). These under-voltage conditions can be mitigated by direct under-voltage load-tripping at RS-T.

Table 13. OUTCOME OF MULTIPLE CONTINGENCIES

Multiple Contingency	Impacted Elements	Study Year
Loss of Toluca – Hollywood 230kV Lines 1 & 3 and Toluca-Hollywood 138kV Line 2	None	2016
Loss of Rinaldi – Tarzana 230kV Lines 1 & 2 and Northridge-Tarzana 230kV Line 1	Voltage collapse	
Loss of Rinaldi – Tarzana 230kV Lines 1 & 2 and Northridge-Tarzana 230kV Line 1 with under-voltage load-tripping at RS T	None	

Light Winter Scenarios. Heavy summer studies test the ability of LADWP's transmission system to handle disturbances when equipment are most vulnerable to thermal overloads and the system is susceptible to under-voltage due to the heavy electricity demand. Light winter studies, on the other hand, test the ability of the transmission system to handle over-voltage concerns because the network is intact but only modestly loaded.

Operationally, LADWP imports electricity from the east and Intermountain and exports to the Pacific Northwest through the Pacific DC Intertie during the winter, but imports electricity from the east, Intermountain, and the Pacific Northwest during the summer. By investigating both summer and winter conditions, this 2011 Assessment provides a comprehensive test of LADWP's transmission facilities to ensure these assets operate within their ratings and within their thermal, voltage, and stability limits.

Light winter scenarios for Winter 2012 and Winter 2016 were developed from the WECC-approved 2011-12 LW1A operating case which models the anticipated operating conditions with heavy power flows into the Pacific Northwest. The light winter studies were conducted with the same rigor as the heavy summer studies.

Table 14 summarizes the power flows along major transmission corridors in these study cases that are relevant to this 2011 Assessment.

Table 14. POWER FLOWS ALONG MAJOR SOUTHERN CALIFORNIA TRANSMISSION CORRIDORS IN LIGHT WINTER STUDY CASES

TRANSMISSION CORRIDOR	RATING (MW)	BASE CASE YEAR			
		2012		2016	
		Power Flow (MW)	% of Rating	Power Flow (MW)	% of Rating
Pacific DC Intertie (Path 65), *South- to-North*	3100	1850	60%	1850	60%
Intermountain DC Line (Path 27)	2400	1747	73%	1748	73%
East-of-the-Colorado River (Path 49)	9300	3882	42%	3882	42%
West-of-the-Colorado River (Path 46)	10623	4681	44%	4682	44%
Victorville - Lugo 500kV Line 1 (Path 61)	2400	665	28%	654	27%
LADWP - SCE @ Sylmar (Path 41)	1600	380	24%	396	25%
Adelanto - Toluca 500kV Line 1	4000	845	72%	853	72%
Adelanto - Rinaldi 500kV Line 1		882		883	
Victorville - Rinaldi 500kV Line 1		800		801	
Victorville - Century1 287kV Line 1		172		174	
Victorville - Century2 287kV Line 1		172		174	

Table 15 aggregates the receiving station bank loads according to their district assignments.

Table 15. DISTRICT LOADS IN LIGHT WINTER STUDY CASES (MW)

Service Area	2012	2016
Central	1141	1185
Southern	160	167
Valley	1041	1081
Total Receiving Station Load	**2342**	**2433**

Table 16 confirms the expectation that off-peak demand is served primarily from out-of-basin fossil resources acquired through ownership and long-term purchase agreements.

Table 16. GENERATION MIX IN LIGHT WINTER STUDY CASES (MW)

Resource Type	Capacity	2012	2016
Pumped Storage	1540	(381)	(296)
Natural Gas	3538	1145	1145
Wind	135	92	92
Solar	319	0	0
Hydroelectric	221	50	50
Internal Generation	***5753***	**906**	**991**
% Total Generation	*67%*	*27%*	*28%*
Hydroelectric	491	340	340
Wind	300	80	80
Coal	1681	1681	1681
Nuclear	387	387	387
External Generation	***2859***	**2488**	**2488**
% Total Generation	*33%*	*73%*	*72%*
Total Generation	**8612**	**3394**	**3479**

For the winter conditions studied in 2012 and 2016, LADWP's transmission facilities are expected to operate within their ratings and within their thermal and voltage limits for (N-0), (N-1), and (N-2) contingencies.

Stability. The 2012, 2016, and 2021 heavy summer cases and the 2016 light winter study cases described in this 2011 Assessment were tested for transient and post-transient performance under the (N-1) and (N-2) contingencies described in Appendix G. There were no violations and no stability limitations in these studies. Typical plots from these studies are provided in Appendix I.

Summary of Findings

Note: NERC requires evidence to be placed in the body of the report, not in the Executive Summary. The next three pages repeat information in the Executive Summary.

This 2011 Assessment does not indicate any Interconnection Reliability Operating Limit conditions or any post-contingency stability limits in the next ten years.

Full analyses of all credible outages listed in Appendix F reveals the existing and planned system should be able to sustain every studied contingency except for the following:

(1) A simultaneous (N-2) outage of Rinaldi-Tarzana 230kV Lines 1 & 2 as early as Summer 2012 would overload the terminal equipment on Northridge-Tarzana 230kV Line 1

(2) A simultaneous (N-2) outage of the Tarzana-Olympic 230kV Line 1 & the Tarzana-Olympic 138kV Line 1 during a summer heat storm would likely overload Scattergood-Olympic 230kV Line 2 until Scattergood-Olympic 230kV Line 1 is placed in service in 2014.

(3) A simultaneous (N-2) outage of Rinaldi-Tarzana 230kV Lines 1 & 2 during a summer heat storm would overload likely Scattergood-Olympic 230kV Line 2 until Scattergood-Olympic Line 1 is placed in service in 2014

(4) A simultaneous (extreme event) outage of three elements Rinaldi-Tarzana 230kV Lines 1& 2 and Northridge-Tarzana 230 kV Line 1) during a summer heat storm in 2014 would cause local low voltages at RS-U (Tarzana) and RS-T (Canoga)

(5) Planned solar projects between Inyo substation and Cottonwood tap would cause severe low voltage violations at Cottonwood as early as Summer 2020

(6) A single (N-1) outage of Haskell Canyon-Rinaldi 230 kV Line may overload the Haskell Canyon-Sylmar 230 kV Line as early as.Summer 2020

To mitigate these overloads, the following corrective actions are recommended. These measures will satisfy the applicable NERC planning standards for contingency or post-contingency system performance [d] :

(1) During the 2012 Summer Peak, continue using a selective load-shedding program at RS-U (Tarzana) to relieve the overload on the Northridge-Tarzana 230kV Line 1 during a double contingency outage of Rinaldi-Tarzana 230kV Lines 1 & 2. The load-shedding will be needed until the ampacity-limited terminal equipment (circuit breakers and disconnects) on the Northridge-Tarzana 230kV Line 1 are changed out in 2013.

The following three recommendations all utilize load shedding as an interim measure until the new Scattergood-Olympic 230 kV Line 1 is put in-service in June 2015:

(2) Through 2014, implement a selective load-shedding program at RS-K (Olympic) to relieve the overload on Scattergood-Olympic 230kV Line 2 during a double contingency outage of Tarzana-Olympic 230kV Line 1 and the Tarzana-Olympic 138kV Line 1.

[d] NERC TPL-002-0b for N-1 (Category B) , NERC TPL-003-0a for N-2 (Category C)

(3) Through 2014, implement a selective load-shedding program at RS-U (Tarzana) and RS-K (Olympic) to relieve the overload on Scattergood-Olympic 230kV Line 2 during a double contingency outage of Rinaldi-Tarzana 230kV Lines 1 & 2.

(4) Starting with Summer 2014, implement a selective under-voltage load-shedding program at RS-T to mitigate local low voltages at RS-U (Tarzana) and RS-T (Canoga) for the simultaneous outage of Rinaldi-Tarzana 230kV Lines 1& 2 and Northridge-Tarzana 230 kV Line 1. This 3-line outage is considered an extreme event.

(5) Before Summer 2020, resolve the low voltage violation at Cottonwood tap by constructing a new Cottonwood 230 kV substation and adding a new 100 MVAR capacitor bank.

(6) Before Summer 2020, resolve overloads on the Haskell Canyon-Sylmar 230 kV Line during a loss of the Haskell Canyon-Rinaldi 230 kV Line 1 by completing two actions:

- Relocate the 230/115 kV Banks from Olive Switching Station to Haskell Canyon Switching Station.

- Replace the existing twin 115 kV circuits between Haskell Canyon Switching Station and Olive Switching Station with a single new 230 kV circuit along existing 115 kV right-of-way. Extend the wire from Olive Switching Station to Sylmar Switching Station using the vacant position on the existing towers

Table 17 summarizes the findings and recommendations of the 2011 Assessment.

Table 17. FINDINGS AND RECOMMENDATIONS

Rec. No.	Year	Outage(s)	Reliability Category	Overloaded Line or System Violation	Recommendation
1	Summer Peak 2012	Rinaldi-Tarzana 230kV Lines 1 & 2	C (TPL-003-0a)	Terminal equipment on Northridge-Tarzana 230kV Line 1	Selectively shed load at RS-U (Tarzana) (~40 MW) for short term. Upgrade circuit breakers and disconnects to higher rating.
2	Summer Peak 2012 Through Summer Peak 2014	Tarzana-Olympic 230kV Line 1 & Tarzana-Olympic 138kV Line 1	C (TPL-003-0a)	Scattergood-Olympic 230kV Line 2	Selectively shed load at RS-K (Olympic) (~200 MW) and RS-U (~90 MW) for short term. Add new Scattergood-Olympic 230 kV Line 1 for long term.
3	Summer Peak 2012 Through Summer Peak 2014	Rinaldi-Tarzana 230kV Lines 1& 2	C (TPL-003-0a)	Scattergood-Olympic 230kV Line 2	Selectively shed load at RS-K (Olympic) (~200 MW) and RS-U (~90 MW) for short term. Add new Scattergood-Olympic 230 kV Line 1 for long term.
4	Summer Peak 2014 Onward	Rinaldi-Tarzana 230kV Lines 1& 2 and Northridge-Tarzana 230 kV Line 1	D (TPL-004-0)	Local voltage collapse	Suggested under-voltage load shedding program in RS-T.
5	Summer 2020	No Outage	A (TPL-001-0.1)	Low voltage violation at Cottonwood tap due to the addition of the planned solar projects	Construct a new Cottonwood 230 kV substation with a new 100 MVAR capacitor bank.
6	Summer Peak 2020	Haskell Canyon-Rinaldi 230 kV Line 1	B (TPL-002-0b)	Haskell Canyon-Sylmar 230 kV Line 1	Two actions are needed: • Relocate the 230/115 kV Banks from Olive Switching Station to Haskell Canyon Switching Station. • Replace the existing twin 115 kV circuits between Haskell Canyon Switching Station and Olive Switching Station with a single new 230 kV circuit along existing 115 kV right-of-way. Extend the wire from Olive Switching Station to Sylmar Switching Station using the vacant position on the existing towers.

Recommendations

#1. Resolve potential overloads on the terminating equipment on Northridge-Tarzana 230kV Line 1 due to loss of Rinaldi-Tarzana 230kV Lines 1 & 2.

- *Implement a Load Shedding Program in RS-U (Tarzana) when Rinaldi-Tarzana 230kV Lines 1 & 2 are lost.* The problem is resolved once Northridge-Tarzana 230kV Line 1 and its terminal equipment are upgraded to provide additional capacity in 2012. The limiting terminal equipment include 5 Circuit Breakers and 8 disconnects at RS-J and RS-U. In the interim, as much as 40MW may be shed.

#2. Resolve potential overloads on Scattergood-Olympic 230kV Line 2 due to a loss of Tarzana-Olympic 230kV & 138 kV Lines.

Implement a selective load-shedding program at RS-K (Olympic) and RS-U (Tarzana) to relieve the overload. The problem is resolved upon completion of the new Scattergood-Olympic 230 kV Line 1 in June 2015. In the interim, as much as 200MW at RS-K (Olympic) and 90 MW at RS-U (Tarzana) may be subject to shedding.

#3. As early as Summer 2014, resolve potential overloads on Scattergood-Olympic 230kV Line 2 due to a loss of Rinaldi-Tarzana 230kV Lines 1 & 2.

- *Implement a selective load-shedding program at RS-U (Tarzana) and RS-K (Olympic) to relieve the overload.* The problem is resolved upon completion of the new Scattergood-Olympic 230 kV Line 1 in June 2015. In the interim, as much as 200MW at RS-U (Tarzana) and 90 MW at RS-U (Olympic) may be subject to shedding.

#4. Implementation of corrective action is not required by TPL-004 but this Assessment provides a recommendation to the Transmission Operator to implement a direct load shedding scheme at RS-T (Canoga) from 2014 onward[e].

#5. Resolve low voltage violation at Cottonwood tap due to the addition of a planned solar project in the area.

- *Construct a new Cottonwood substation with a new 100 MVAR capacitor bank*

#6. As early as Summer 2020, resolve potential overloads on Haskell Canyon-Sylmar 230 kV Line 1 during a loss of the Haskell Canyon-Rinaldi 230 kV Line 1.

This recommendation is the same as recommendation #6 in the 2010 Assessment. It was also confirmed by studies performed during 2011 for statewide planning by the California Transmission Planning Group.

[e] Recommendation 4 in the 2011 Assessment is the same as Recommendation 5 in the 2009 Assessment. The 2009 Assessment evaluated only model year 2014 for this event, and the 2011 Assessment evaluated only model year 2016 for this event; the recommendation from the 2009 Assessment is still valid, so the recommendation indicating the earliest need to act (2014) is kept in the 2011 Assessment.

Two actions are needed:

- *Relocate the 230/155 kV Banks from Olive Switching Station to Haskell Canyon Switching Station.*
- Replace the existing twin 115 kV circuits between Haskell Canyon Switching Station and Olive Switching Station and with a single new 230 kV circuit along existing 115 kV right-of-way. Extend the wire from Olive Switching Station to Sylmar Switching Station using the vacant position on the existing towers.

Implementation Plan for these Recommendations

#1: Design work to increase the capacity of the Northridge-Tarzana 230kV Line 1 has commenced. The reconductor work is budgeted and the expected in-service date is prior to Summer 2012. The budget for the terminal equipment upgrades is being developed. The Load Shedding Program in RS-U (Tarzana) is an interim solution that be used until the entire project is upgraded.

#2 and #3: The Scattergood-Olympic 230kV Line 1 is budgeted and has an expected in-service date of June 2015. This project is beyond the current budget cycle, but will appear in the 2012-2013 budget. The Load Shedding Programs at RS-U (Tarzana) and RS-K (Olympic) are interim solutions that will be used until the project is placed in-service.

#4: Implementation of corrective action is not required for this Category D contingency. No budget for the under-voltage load shed has been developed.

#5: This project is beyond the current budget cycle. It is expected to appear in the 2017-2018 budget.

#6: This project is beyond the current budget cycle. It is expected to appear in the 2017-2018 budget.

Comparison with Recommendations in the 2010 Ten-Year Transmission Assessment

Changes to previous recommendations

Recommendation #1 completion of the terminal equipment upgrade may be delayed.

Recommendation #2 completion of new Scattergood-Olympic 230kV Line #1 is delayed one year to July 2015 and the load-shedding is more aggressive: (2010) 60 MW at RS-K to (2011) 200MW at RS-K plus 90 MW at RS-U.

Recommendation #3 completion of new Scattergood-Olympic 230kV Line #1 is delayed one year to July 2015 and the load-shedding is more aggressive: (2010) 40 MW at RS-K to (2011) 200MW at RS-K plus 90 MW at RS-U.

Recommendation #4 matches Recommendation #5 in the 2010 Assessment.

Recommendation #6 is identical

Recommendation #5 is New

Relay Coordination with adjacent Planning Coordinator Areas for 115 kV and 138 kV Facilities (PRC-023-1 R3)

TPL-001, TPL-002 and TPL-003 provide a screen to determine the facilities that are critical to the reliability of the Bulk Electric System. This process, carried out in this 2011 Assessment by LADWP in its role as a Planning Coordinator, has determined that there are no existing or currently planned facilities to report per PRC-023-1 R3: there are no planned or existing qualifying facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in the LADWP Planning Coordinator Area that are critical to the reliability of the Bulk Electric System

This page is intentionally left blank

Appendix A. NERC/WECC Planning Standards

This page is intentionally left blank

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-0.1

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:** May 13, 2009

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, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, 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 conditions defined in Category A of Table I. To be considered 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 A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no 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.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_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 these reliability assessments and corrective plans and shall annually provide these to its respective NERC 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-001-0_R1 and TPL-001-0_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-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention
None specified.

1.4. Additional Compliance Information

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
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised

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 No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes	 No [b] No [b] No [b]	 No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 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]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

<table>
<tr>
<td>D [d]

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

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.

A. Introduction

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

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

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:** Immediately after approval of applicable regulatory authorities.

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
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Addition

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 No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 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]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] 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): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 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 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ 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 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

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).

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

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.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

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 C of Table 1 (multiple 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).

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

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.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement

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).

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

Background Information for Interpretation

Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:

1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)."
2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)."
3. "Include the effects of existing and planned protection systems, including any backup or redundant systems."

Category B of Table 1 (single Contingencies) specifies:

Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:

1. Generator
2. Transmission Circuit
3. Transformer

Loss of an Element without a Fault.

Single Pole Block, Normal Clearing[e]:

4. Single Pole (dc) Line

Note e specifies:

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.

The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."

Conclusion

TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.

This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-0a

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 23, 2010

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems 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 C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. 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 C of Table 1 (multiple 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 C 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 Table 1 for Category C 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 C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_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 these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC 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-003-0_R1 and TPL-003-0_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-003-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

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
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0a	April 23, 2010	FERC approval of interpretation of TPL-003-0 R1.3.12	Interpretation

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 [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 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]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] 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): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 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 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ 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 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

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).

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

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.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

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 C of Table 1 (multiple 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).

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

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.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, ‘critical system conditions’ in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number**: TPL-004-0

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 evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

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 D contingencies of Table I. The specific elements selected (from within 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 D 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. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. 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. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC 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 for its system responses as specified in Reliability Standard TPL-004-0_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

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: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

B. Regional Differences

1. None identified.

Version History

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

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 No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 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]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] 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): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 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 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ 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.

This page is intentionally left blank

Appendix B. Receiving Station Loads

This page is intentionally left blank

Appendix B. RECEIVING STATION LOADS

SERVICE AREA	RECEIVING STATION		BASECASE YEAR																					
			2011		2012		2013		2014		2015		2016		2017		2018		2019		2020		2021	
			MW	Mvar	MW	Mvar	MW	Mvar	MW	Mvar	MW	Mvar	MW	Mvar	MW	Mvar	MW	Mvar	MW	Mvar	MW	Mvar	MW	Mvar
CENTRAL	RS-N	AIRPORT	204	63	206	63	206	63	208	64	211	65	216	66	219	67	220	68	224	69	227	70	232	71
	RS-G	ATWATER	311	69	308	69	310	69	317	71	317	71	322	72	327	73	332	74	336	75	341	76	347	78
	RS-B	CENTURY	296	73	295	73	295	73	304	75	310	76	314	77	317	78	320	79	327	81	332	82	338	83
	RS-D	FAIRFAX	393	97	388	96	388	96	391	97	399	98	401	99	407	100	409	101	413	102	418	103	426	105
	RS-H	HOLLYWOOD	378	72	386	73	389	74	396	75	404	77	414	79	418	79	424	80	430	81	437	83	444	84
	RS-P	MARKET (RIVER)	362	56	361	56	358	55	362	56	366	56	368	57	370	57	374	58	375	58	381	59	388	60
	RS-K	OLYMPIC	402	116	405	117	404	117	417	121	423	122	430	124	437	126	442	128	448	130	455	132	463	134
	RS-L	SCATTERGOOD	26	12	26	12	26	12	27	13	27	13	27	13	27	13	27	13	27	13	27	13	28	13
	RS-A	ST JOHN	220	50	219	50	218	50	223	51	226	52	230	53	231	53	234	53	236	54	239	55	244	56
	RS-F	VELASCO	219	48	218	48	220	48	222	49	225	49	228	50	229	50	234	51	235	52	238	52	243	53
	Total Central Load		2811	656	2811	656	2814	657	2867	670	2908	679	2950	689	2982	697	3015	705	3049	713	3095	724	3153	737
SOUTHERN	RS-HAL	HALLDALE	44	17	47	18	47	18	47	18	49	18	49	18	51	19	51	19	51	19	52	19	53	20
	RS-Q	HARBOR	198	60	198	60	198	60	200	61	203	61	205	62	207	63	209	63	212	64	214	65	218	66
	RS-C	WILMINGTON	161	20	160	20	160	20	164	20	165	21	166	21	169	21	169	21	171	21	174	22	178	22
	Total Southern Load		403	97	405	97	405	97	411	98	417	100	420	101	427	103	429	103	434	104	440	106	449	108
VALLEY	RS-T	CANOGA	361	66	361	66	360	66	365	67	371	68	375	69	367	67	370	68	373	68	679	70	387	71
	RS-V	CHATSWORTH																						
	RS-J	NORTHRIDGE	525	98	525	98	521	98	532	100	542	102	550	103	570	107	577	108	586	110	594	111	606	114
	RS-RIN	RINALDI	278	68	280	69	286	70	291	72	297	73	305	75	310	76	314	77	319	78	324	80	330	81
	RS-U	TARZANA	331	64	334	64	335	65	341	66	349	67	354	68	357	69	363	70	369	71	375	72	382	74
	RS-E	TOLUCA	392	82	389	81	389	81	390	81	397	83	405	84	409	85	415	87	422	88	429	89	437	91
	RS-M	VALLEY	299	86	303	87	304	87	311	89	314	90	314	90	322	93	327	94	332	95	337	97	342	98
	RS-S	VAN NUYS	406	55	408	55	410	55	421	57	429	58	439	59	443	60	449	60	457	61	464	63	472	64
	Total Valley Load		2591	519	2598	520	2604	522	2652	531	2700	541	2742	549	2778	556	2815	564	2858	573	3202	581	2956	592
TOTAL RECEIVING STATION LOAD			**5805**	**1272**	**5814**	**1274**	**5822**	**1276**	**5930**	**1300**	**6025**	**1320**	**6112**	**1339**	**6186**	**1356**	**6260**	**1372**	**6340**	**1390**	**6737**	**1411**	**6558**	**1438**

This page is intentionally left blank

Appendix C. Generation Schedule for LADWP-Owned Facilities (MW)

This page is intentionally left blank

Appendix C. Generation Schedule for LADWP-Owned Facilities (MW)

GEN UNIT	kV	NET MAX. UNIT CAPABILITY * (MW)	BASE CASE YEAR 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
CASTAI1G	18	240	110	117	118	97	82	147	160	190	68	195
CASTAI2G	18	265									200	200
CASTAI3G	18	240									200	200
CASTAI4G	18	265									200	200
CASTAI5G	18	265									200	200
CASTAI6G	18	265									200	200
PUMPED STORAGE		1540	110	117	118	97	82	147	160	190	1068	1195
OWENS UP	11.5	37.5	37	37	37	37	37	37	37	37	37	37
OWENSCON	11.5	37.5	36	36	36	36	36	36	36	36	36	36
OWENSMID	11.5	37.5	37	37	37	37	37	37	37	37	37	37
PP 1 G	7.5	76	40	40	40	40	40	40	40	40	40	40
PP 2 G	7.5	32	10	10	10	10	10	10	10	10	10	10
HOOVER		491	410	410	410	410	410	410	410	410	410	410
HYDRO		712	570	570	570	570	570	570	570	570	570	570
HARB1G	13.8	82	81	81	81	81	81	81	81	81	81	81
HARB2G	13.8	82	81	81	81	81	81	81	81	81	81	81
HARB5G	13.8	65	65	65	65	65	65	65	65	65	65	65
HARBCT10	13.8	47.4										
HARBCT11	13.8	47.4										
HARBCT12	13.8	47.4										
HARBCT13	13.8	47.4										
HARBCT14	13.8	47.4										
HAYNES1G	18	222	150	150	100	100	120	120	100	120	200	200
HAYNES2G	18	222	150	150	100	100	120	120	100	120	200	200
HAYNES5G	18	292										
HAYNES6G	18	243										
HAYNES8G	18	250	200	200	200	200	200	200	200	200	240	240
HAYNES9G	18	162.5	150	150	150	150	150	150	150	150	150	150
HAYNS10G	18	162.5	150	150	150	150	150	150	150	150	150	150
HYN1112G	13.8	100									100	100
HYN1112G	13.8	100									100	100
HYN1314G	13.8	100									100	100
HYN1314G	13.8	100									100	100
HYN1516G	13.8	100									100	100
HYN1516G	13.8	100										
SCATT1G	18	183	170	170	170	170	170	170	170	170		
SCATT2G	18	184									150	150
SCATT3G	24	450	400	400	400	400						
SCATT4ST	13.8	210					100	100	100	100	200	200
SCATT5GT	13.8	100					100	100	100	100	100	100
SCATT6GT	13.8	100					100	100	100	100	100	100
SCATT7GT	13.8	100					100	100	100	100	50	50
VALLEY5G	13.8	43										
VALLEY6G	18	163	145	145	145	145	145	145	145	145	150	150
VALLEY7G	18	163	100	100	100	100	100	100	100	100	150	150
VALLEY8G	18	207	100	100	100	100	100	100	100	100	210	210
NATURAL GAS		3538	1942	1942	1842	1842	1882	1882	1842	1882	2777	2777
PTSOL	0.48	8.5	8	8	8	8	8	8	8	8	8	8
AD SOLAR	0.26	10	10	10	10	10	10	10	10	10	10	10
BEACONPV	0.29	270			153	208	208	208	208	208	208	208
OWENYO_S	0.48	200			100	150	200	200	200	200	200	200
ODLSR	0.21	100					25	50	75	100	100	100
SOLAR		588.5	18	18	271	376	451	476	501	526	526	526
PTWTG	0.57	135	82	82	82	82	82	82	82	82	82	82
PCWTG	0.57	150							91	91	91	91
WTGCP	0.69	100	40	40	40	40	40	40	40	40	40	40
WTGGE	0.57	100	40	40	40	40	40	40	40	40	40	40
WTGGE2	0.57	100	40	40	40	40	40	40	40	40	40	40
WIND		585	202	202	202	202	202	202	292	292	292	292
NAVAJO 1	26	159	159	159	159	159	159	159	159	0	0	0
NAVAJO 2	26	159	159	159	159	159	159	159	159	0	0	0
NAVAJO 3	26	159	159	159	159	159	159	159	159	0	0	0
INTERMT1G	26	546	546	546	546	546	546	546	546	546	546	546
INTERMT2G	26	546	546	546	546	546	546	546	546	546	546	546
COAL		1569	1569	1569	1569	1569	1569	1569	1569	1092	1092	1092
PALOVRD1	24	129	129	129	129	129	129	129	129	129	129	129
PALOVRD2	24	129	129	129	129	129	129	129	129	129	129	129
PALOVRD3	24	129	129	129	129	129	129	129	129	129	129	129
NUCLEAR		387	387	387	387	387	387	387	387	387	387	387
TOTAL LADWP GENERATION		**8919**	**4797**	**4805**	**4958**	**5043**	**5142**	**5233**	**5321**	**4939**	**6712**	**6839**

Appendix X. Generation Schedule of LADWP-Owned Facilities (MW)
(Light Winter Study Case)

GENERATING UNIT	kV	NET MAX. UNIT CAPABILITY * (MW)	BASE CASE YEAR	
			2011lw12-lml	2011lw16-lml
CASTAI1G	18	240	(184)	(96)
CASTAI2G	18	265	(200)	(200)
CASTAI3G	18	240		
CASTAI4G	18	265		
CASTAI5G	18	265		
CASTAI6G	18	265		
	PUMPED STORAGE	1540	(384)	(296)
OWENS UP	11.5	37.5		
OWENSCON	11.5	37.5		
OWENSMID	11.5	37.5		
PP 1 G	7.5	76	40	40
PP 2 G	7.5	32	10	10
HOOVER		491	410	410
	HYDRO	712	460	460
HARB1G	13.8	82		
HARB2G	13.8	82		
HARB5G	13.8	65		
HARBCT10	13.8	47.4		
HARBCT11	13.8	47.4		
HARBCT12	13.8	47.4		
HARBCT13	13.8	47.4		
HARBCT14	13.8	47.4		
HAYNES1G	18	222	112	112
HAYNES2G	18	222		
HAYNES5G	18	292		
HAYNES6G	18	243		
HAYNES8G	18	250	200	200
HAYNES9G	18	162.5	150	150
HAYNS10G	18	162.5	150	150
HYN1112G	13.8	100		
HYN1112G	13.8	100		
HYN1314G	13.8	100		
HYN1314G	13.8	100		
HYN1516G	13.8	100		
HYN1516G	13.8	100		
SCATT1G	18	183		
SCATT2G	18	184	85	85
SCATT3G	24	450		
SCATT4ST	13.8	210		
SCATT5GT	13.8	100		
SCATT6GT	13.8	100		
SCATT7GT	13.8	100		
VALLEY5G	13.8	43		
VALLEY6G	18	163	150	150
VALLEY7G	18	163	150	150
VALLEY8G	18	207	200	200
	NATURAL GAS	3538	1197	1197
PTSOL	0.48	8.5		
AD SOLAR	0.26	10		
BEACONPV	0.29	270		
OWENYO_S	0.48	200		
ODLSR	0.21	100		
	SOLAR	588.5	0	0
PTWTG	0.57	135	40	40
PCWTG	0.57	150		
WTGCP	0.69	100	40	40
WTGGE	0.57	100	20	40
WTGGE2	0.57	100	20	20
	WIND	585	120	140
NAVAJO 1	26	159	0	0
NAVAJO 2	26	159	0	0
NAVAJO 3	26	159	0	0
INTERMT1G	26	546	546	546
INTERMT2G	26	546	546	546
	COAL	1569	1092	1092
PALOVRD1	24	129	129	129
PALOVRD2	24	129	129	129
PALOVRD3	24	129	129	129
	NUCLEAR	387	387	387
TOTAL LADWP GENERATION		**8919**	**2872**	**2980**

RENEWABLE ENERGY RESOURCES REPRESENTED IN THE HEAVY SUMMER 2020 BASECASE

TECHNOLOGY	LOCATION	MAXIMUM INSTALLED CAPACITY (MW)	GENERATION DISPATCH (MW)	ENERGY (Gwh)
BIOMASS				
Atmos Energy Landfill Gas	Texas	0	N/A	288
Hyperion Digester Gas	Los Angeles	16	N/A	147
Lopez Microturbine	Los Angeles	1.5	N/A	2
Shell Energy Landfill Gas	Texas & Arkansas	0	N/A	350
Toyon Power Plant	Los Angeles	3.6	N/A	12
WM Bradley	Los Angeles	6	N/A	36
Lanfill Gas Purchase		N/A	N/A	520
SMALL HYDRO				
Aqueduct & Owens Valley	Aqueduct & Owens Valley	54	50	287
Owens Gorge	Owens Valley	110	110	261
MWD Sepulveda	Los Angeles	8.5	N/A	42
Castaic U3&U5 Upgrade	Los Angeles	30	30	15
Castaic U1 Upgrade	Los Angeles	15	15	7.5
Aquaduct PP Improvements	Owens Valley	4	4	30
Powerex - BC Hydro	British Columbia	50	50	430
North Hollywood PS Power Plant	Los Angeles	1	N/A	5
Water System Hydro	Los Angeles	4	0	22
SOLAR				
LADWP-Built Solar (In-Basin)	Los Angeles	100	N/A	180
LADWP-Built Solar	Los Angeles	1	N/A	1.4
Solar Customer Net Metered	Los Angeles	110.5	110*	164
Pine Tree Solar	Tehachapi	8.5	8.5	17
Adelanto Solar	Adelanto	10	10	20
Solar CNM (SB1)	Los Angeles	28.4	N/A	47
Solar 2	Barren Ridge	250	250	550
Solar 10	Owens Valley	200	200	440
Solar 17	Owens Valley	100	100	220
Solar Feed-in-Tariff	Los Angeles	150	N/A	263
GEOTHERMAL				
Geo PPA 2014		30	N/A	237
Imperial County Joint Geo	Imperial County	100	100	800
WIND				
LA-Owned				
Pine Tree	Tehachapi	135	81.5	382
Pine Canyon	Tehachapi	150	90.6	425
PPM Wyoming	Wyoming	82.2	82.2	233
Milford Phase I	Utah	185	40	434
Milford Phase II	Utah	102	40	217
Linden	Pacific Northwest	50	20	145
Pebble Springs	Pacific Northwest	98.7	0	193
Willow Creek	Pacific Northwest	72	0	197
Windy Point	Pacific Northwest	262.2	0	694

* Netting with RS loads

TOTAL =	**8,314**
2020 Forecasted Total Sale =	**25,549**
% Renewables =	**33%**

This page is intentionally left blank

Appendix D. Transmission Line Capacities

This page is intentionally left blank

Appendix D. Transmission Line Capacities

LINE	CONTINUOUS RATING			EMERGENCY RATING		
	AMP	MVA	LIMITING COMPONENT	AMP	MVA	LIMITING COMPONENT
69kV LINES						
Burbank, Toluca -Valley Line 1	850	102	OH Line	977	117	OH Line
Burbank, Toluca -Valley Line 2	765	91	OH Line	879	105	OH Line
Burbank, Toluca -Valley Line 3	765	91	OH Line	879	105	OH Line
Burbank, Toluca - Capon Line 1	686	82	OH Line	789	94	OH Line
Burbank, Toluca - Capon Line 2	769	92	OH Line	884	106	OH Line
Burbank, Toluca - Capon Line 3	765	91	OH Line	879	105	OH Line
RS - E 230 - 69KV Bank E (MUNI)	-	403	Xfmr E	-	403	Xfmr E
RS - E 230 - 69KV Bank F (MUNI)	-	403	Xfmr F	-	403	Xfmr F
115kV LINES						
Power Plant 1 - Power Plant 2 Tie Line	443	88	OH Line	600	120	Circuit breaker
Power Plant 1 - Olive Line 1	-	80	Xfmr H	-	90	Xfmr H
Power Plant 2 - Olive Line 1	443	88	OH Line	600	120	Disc Sw & CB
138kV LINES						
Century - Gramercy Line 1	763	182	OH Line	1200	287	Wave Trap
Century - Gramercy Line 2	763	182	OH Line	1200	287	Wave Trap
Century - Wilmington Line 1	763	182	OH Line	800	191	Wave Trap
Century - Wilmington Line 2	763	182	OH Line	800	191	Wave Trap
Fairfax - Airport Line 1	1049	251	UG Cable	1163	278	UG Cable
Fairfax - Airport Line 2	1049	251	UG Cable	1163	278	UG Cable
Fairfax - Gramercy Line 1	763	182	OH Line	800	191	Reactor
Fairfax - Gramercy Line 1 Rating with L-2 in svc	664	159	UG Cable	736	176	UG Cable
Fairfax - Gramercy Line 2	763	182	OH Line	800	191	Reactor
Fairfax - Gramercy Line 2 Rating with L-1 in svc	664	159	UG Cable	736	176	UG Cable
Fairfax - Olympic Ca A	800	191	Reactor	800	191	Reactor
Fairfax - Olympic Ca A rating with Ca B in-svc	664	159	UG Cable	736	176	UG Cable
Fairfax - Olympic Ca B	800	191	Reactor	800	191	Reactor
Fairfax - Olympic Ca B rating with Ca A in-svc	664	159	UG Cable	736	176	UG Cable
Harbor - Wilmington Ca A	-	90	Xfmr Bank	-	99	Xfmr Bank (4-hr rating)
Harbor - Wilmington Ca B	-	90	Xfmr Bank	-	99	Xfmr Bank (4-hr rating)
Harbor - Wilmington Ca D	800	191	Disc Sw	800	191	Disc Sw
Harbor - Wilmington Ca E	800	191	Disc Sw	800	191	Disc Sw
Hollywood - Fairfax Ca A	800	191	Reactor	800	191	Reactor
Hollywood - Fairfax Ca A Rating with Ca B in-svc	776	185	UG Cable	800	191	Reactor
Hollywood - Fairfax Cable B	800	191	Reactor	800	191	Reactor
Hollywood - Fairfax Ca B Rating in Ca A in-svc	776	185	UG Cable	800	191	UG Cable
Scattergood - Airport Line 1	979	234	OH Line	1163	278	UG Cable
Scattergood - Airport Line 2	979	234	OH Line	1163	278	UG Cable
Tarzana - Olympic Line 1	837	200	UG Cable	837	200	UG Cable
Tarzana - Olympic Line 1 Rating with 2 circuits in svc	-	290	Xfmr E	-	328	Xfmr E
Toluca - Hollywood Line 2	763	182	OH Line	800	191	Disc Sw
Toluca - Hollywood Line 2 Rating with 2 cables in-svc	1200	287	Disc Sw	1200	287	Disc Sw

Appendix D. Transmission Line Capacities

LINE	CONTINUOUS RATING			EMERGENCY RATING		
	AMP	MVA	LIMITING COMPONENT	AMP	MVA	LIMITING COMPONENT
Wilmington - Gramercy Line 1	763	182	OH Line	932	223	UG Cable
Harbor-Tap 1 Line 1	763	182	OH Line	800	191	Disc Sw
Harbor-Tap 2 Line 2	763	182	OH Line	800	191	Disc Sw
Wilmington - Gramercy Line 2	763	182	OH Line	800	191	Disc Sw
230kV LINES						
Atwater - Air Way Line 1	1778	708	OH Line	2000	797	Wave Trap
Atwater - Air Way Line 2	1778	708	OH Line	2000	797	CB & Disc Sw @ RS-Air Way
Atwater - St John Line 1	1360	541	OH Line	1400	558	Disc Sw
Atwater - Velasco Line 1	1360	541	OH Line	1600	637	CB
Barren Ridge - Rinaldi Line 1	1152	459	OH Line	1635	651	OH Line
Castaic - Northridge Line 1	1797	716	Ground Clearance	1797	716	Ground Clearance
Castaic - Olive Line 1	1911	761	OH Line	2000	797	Disc Sw
Castaic - Sylmar Line 1	1855	739	OH Line	2000	797	Disc Sw
Haynes - Atwater Line 1	1600	637	CB	1600	637	CB
Haynes - River Line 1	1600	637	CB	1600	637	CB
Haynes - St John Line 1	1600	637	CB	1600	637	CB
Haynes - Velasco Line 1	1600	637	CB	1600	637	CB
Intermountain - Gonder Line 1	502	200	System Studies	502	200	System Studies
Inyo - Cottonwood Line 1	1152	459	OH Line	1635	651	OH Line
Inyo - Rinaldi	1152	459	OH Line	1635	651	OH Line
Laguna Bell - Velasco Line 1	861	343	OH Line	-	475	Xfmr Bank G
Mead - McCullough Line 1	899	358	OH Line	1486	591	OH Line
Mead - McCullough Line 2	899	358	OH Line	1486	591	OH Line
Northridge - Tarzana Line 3	1437	572	OH Line	2000	797	Disc Sw
Olive-Northridge Line 1	1600	637	Ground Clearance	1600	637	Ground Clearance
Pine Tree-Barren Ridge Line 1	2008	800	Ground Clearance			
Rinaldi - Airway Line 1	1152	459	OH Line	1635	651	OH Line
Rinaldi - Airway Line 2	1152	459	OH Line	1635	651	OH Line
Rinaldi - Tarzana Line 1	1152	459	OH Line	1635	651	OH Line
Rinaldi - Tarzana Line 2	1152	459	OH Line	1635	651	OH Line
River - Market Cable A	-	160	Xfmr A	-	200	Xfmr A
River - Market Cable B	-	160	Xfmr B	-	200	Xfmr B
River - Market Cable C	-	160	Xfmr C	-	200	Xfmr C
River - Market Cable D	-	170	Xfmr D	-	220	Xfmr D
River - Velasco Line 1	1360	542	OH Line	1600	637	CB
Scattergood - Olympic Line 2	876	349	UG Cable	876	349	UG Cable
St John - River Line 1	1778	708	OH Line	2000	797	Wave Trap
Sylmar - Northridge Line 1	1778	708	OH Line	2518	1003	OH Line
Sylmar - Rinaldi Line 1	1778	708	OH Line	2518	1003	OH Line
Sylmar - Rinaldi Line 3	1782	710	OH Line	2582	1029	OH Line
Sylmar - Rinaldi Line 4	1911	761	OH Line	2767	1102	OH Line
Tarzana - Canoga Cable A	-	160	Xfmr A	-	176	Xfmr A (4-hr rating)

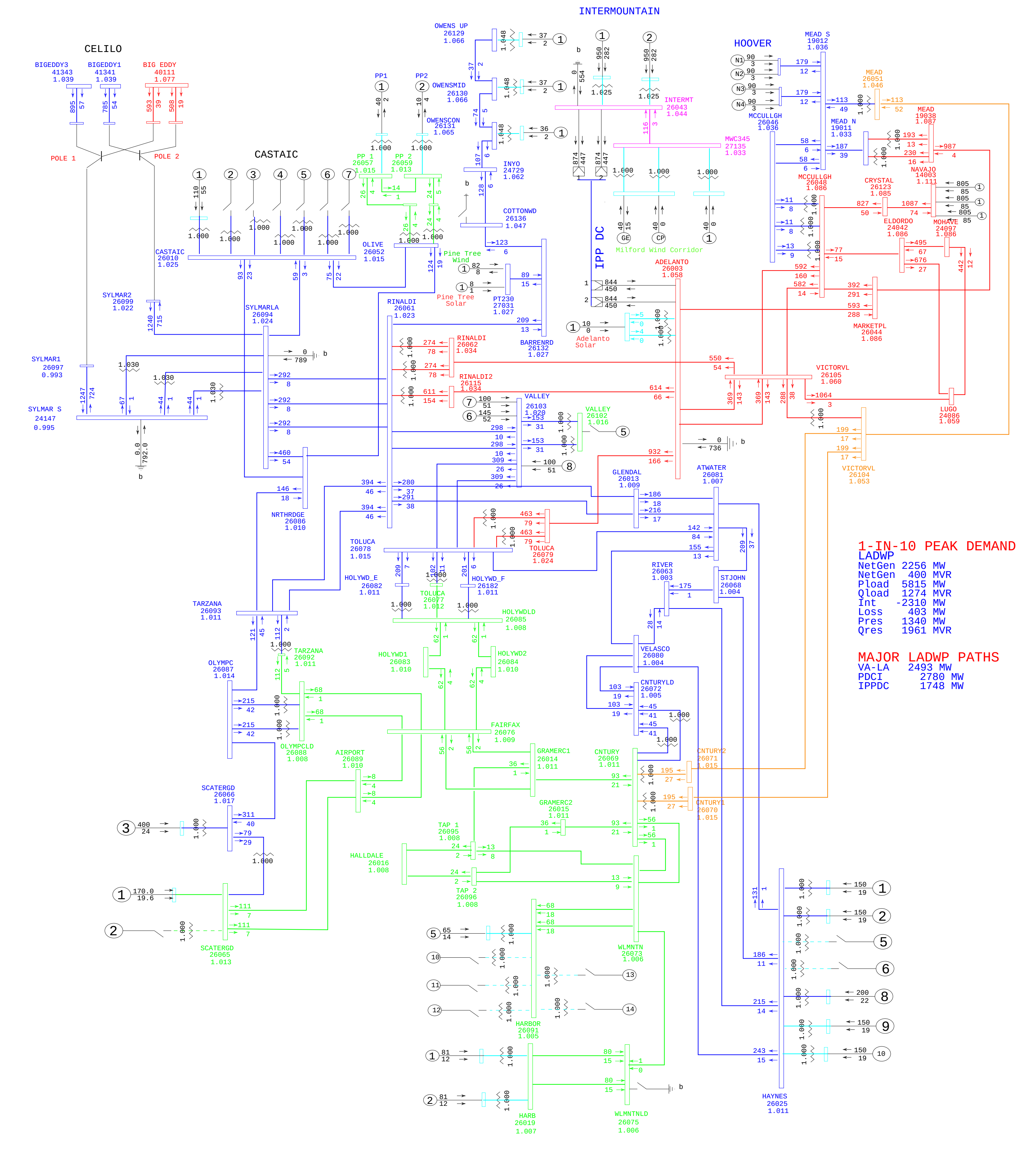
Appendix D. Transmission Line Capacities

LINE	CONTINUOUS RATING			EMERGENCY RATING		
	AMP	MVA	LIMITING COMPONENT	AMP	MVA	LIMITING COMPONENT
Tarzana - Canoga Cable B	-	160	Xfmr B	-	176	Xfmr B (4-hr rating)
Tarzana - Canoga Cable C	-	160	Xfmr C	-	176	Xfmr C (4-hr rating)
Tarzana - Olympic Line 3	958	382	UG Cable	1094	436	UG Cable
Toluca - Atwater Line 1	1778	708	OH Line	2000	797	OH Line
Toluca - Hollywood Line 1	876	349	UG Cable	1002	399	UG Cable
Toluca - Hollywood Line 3	-	400	Xfmr F	1152	459	UG Cable
Toluca - Van Nuys Cable A	-	170	Xfmr A	469	187	Disc Sw & CB
Toluca - Van Nuys Cable B	-	160	Xfmr Bank	-	176	Xfmr Bank
Toluca - Van Nuys Cable C	-	160	Xfmr Bank	-	176	Xfmr Bank
Toluca - Van Nuys Cable D	-	160	Xfmr Bank	-	176	Xfmr Bank
Valley - Rinaldi Line 1	1243	495	OH Line	1805	720	OH Line
Valley - Rinaldi Line 2	1243	495	OH Line	1805	720	OH Line
Valley - Toluca Line 1	1243	495	OH Line	1805	720	OH Line
Valley - Toluca Line 2	1243	495	OH Line	1805	720	OH Line
Velasco - Century Line 1	1600	637	CB	1600	637	CB
Velasco - Century Line 2	1600	637	CB	1600	637	CB
287kV LINES						
Mead - Victorville Line 1	-	420	Xfmr	-	520	Xfmr
Victorville - Century Line 1	-	420	Xfmr F or G	-	510	Xfmr F or G
Victorville - Century Line 2	-	420	Xfmr F or G	-	510	Xfmr F or G
Victorville Sw Sta - Bank K TIE	-	465	Xfmr K	-	573	Xfmr K
345kV LINES						
Intermountain - Mona Line 1	1004	600	System Studies	2000	1195	CB & Disc Sw @ Mona
Intermountain - Mona Line 2	1004	600	System Studies	2000	1195	CB & Disc Sw @ Mona
500kV LINES						
Adelanto - Rinaldi Line 1	1752	1593	RS-RIN CB & Disc SW	1752	1593	RS-RIN CB & Disc SW
Adelanto - Toluca Line 1	2000	1819	SF6 Switchgear	2000	1819	SF6 Switchgear
Crystal - McCullough Line 1	2600	2364	Series Cap	3400	3092	Series Cap (1/2-hr rating)
Eldorado - McCullough Line 1	3000	2728	Disc Sw & CB	3000	2728	Disc Sw & CB
Lugo - Victorville Line 1	2771	2400	System Studies	3000	2728	Wave Trap
Marketplace - Adelanto Line 1	1800	1636	Series Cap	2430	2210	Series Cap (1/2-hr rating)
Marketplace - McCullough Line 1	3822	3475	OH Line	4000	3637	Disc Sw & CB
McCullough - Victorville Line 1	1600	1455	Series Cap	2400	2182	Series Cap
McCullough - Victorville Line 2	1600	1455	Series Cap	2400	2182	Series Cap
Mohave - Eldorado Line 1	1386	2000	Stability	1386	1200	Stability
Mohave - Eldorado Line 1	3000	2728	VAR Comp	3000	2728	VAR Comp
Navajo - Crystal Line 1	2200	2001	Series Cap	2750	2501	Series Cap (1/2-hr rating)
Navajo - Moenkopi Line 1	1630	1412	Series Cap	-	-	
Victorville - Adelanto Line 1	3000	2728	Wave Trap	3000	2728	Wave Trap
Victorville - Adelanto Line 2	3000	2728	Wave Trap	3000	2728	Wave Trap
Victorville - Rinaldi Line 1	1839	1593	SF6 Switchgear	2300	1992	SF6 Switchgear

This page is intentionally left blank

Appendix E. One-Line Diagrams

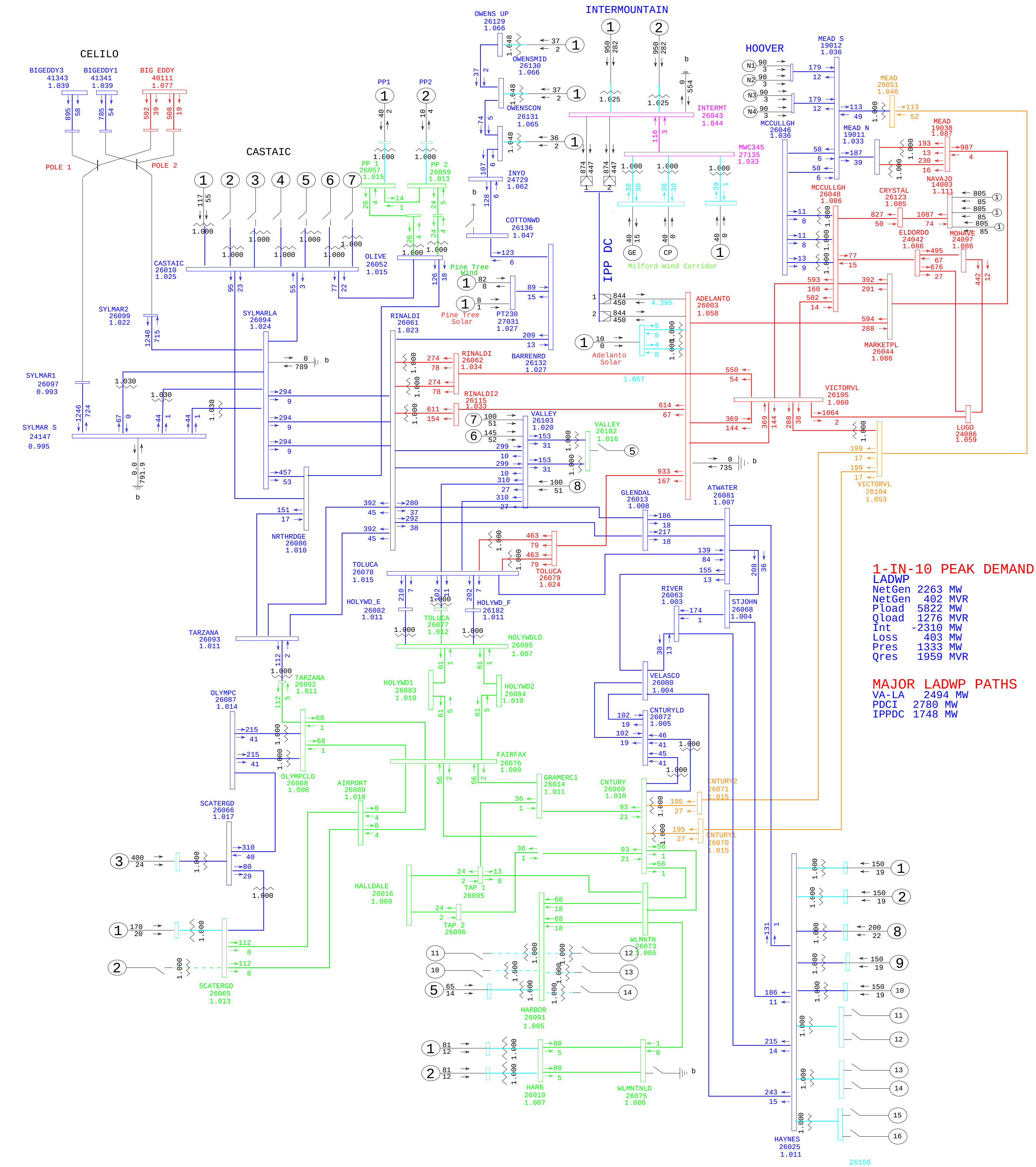
This page is intentionally left blank



General Electric International, Inc. PSLF Program Tue Oct 25 17:39:57 2011 2011hs12.sav

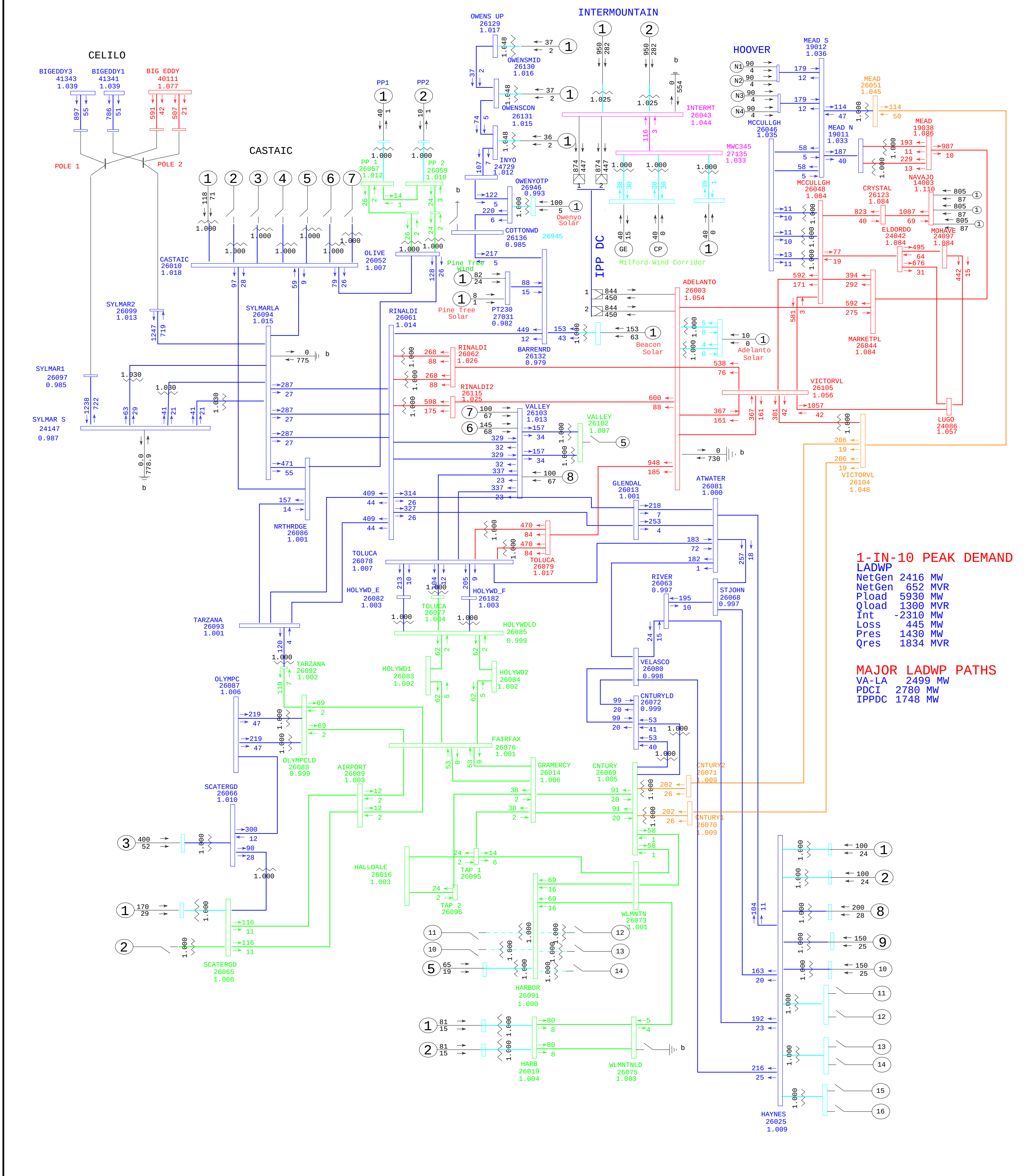
WESTERN ELECTRICITY COORDINATING COUNCIL
11HS2A APPROVED OPERATING CASE
11/2/10 - 2012 DWP 1-in-10 Summer Peak

MW/MVAR
2011hs12.drw
Rating = 1



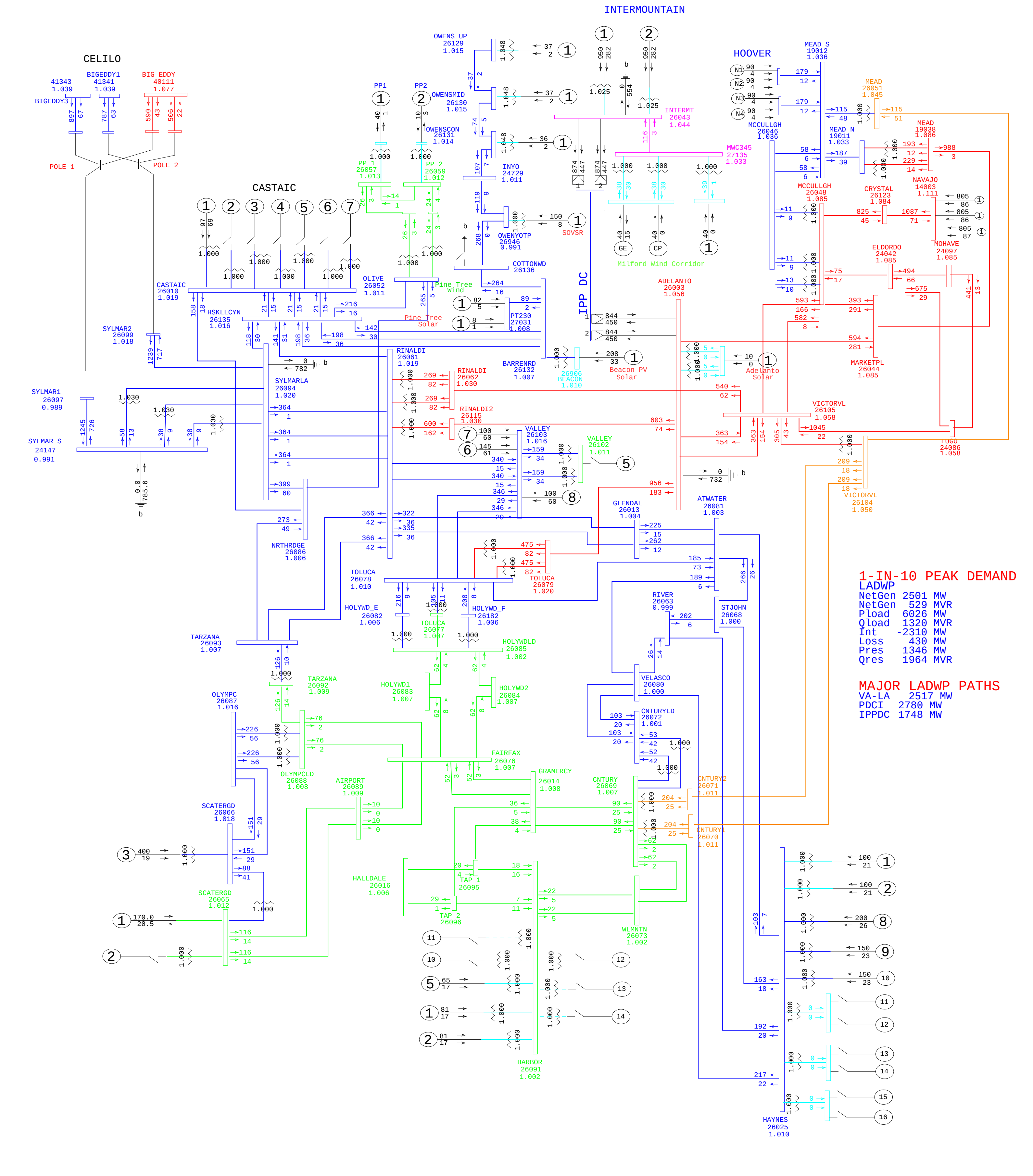
General Electric International, Inc. PSLF Program Tue Oct 25 17:42:23 2011 2011hs13.sav

	WESTERN ELECTRICITY COORDINATING COUNCIL 11HS2A APPROVED OPERATING CASE NOVEMBER 2, 2010	11/2/10 - 2013 DWP 1-in-10 Summer Peak	MW/MVAR 2011hs13.drw Rating = 1



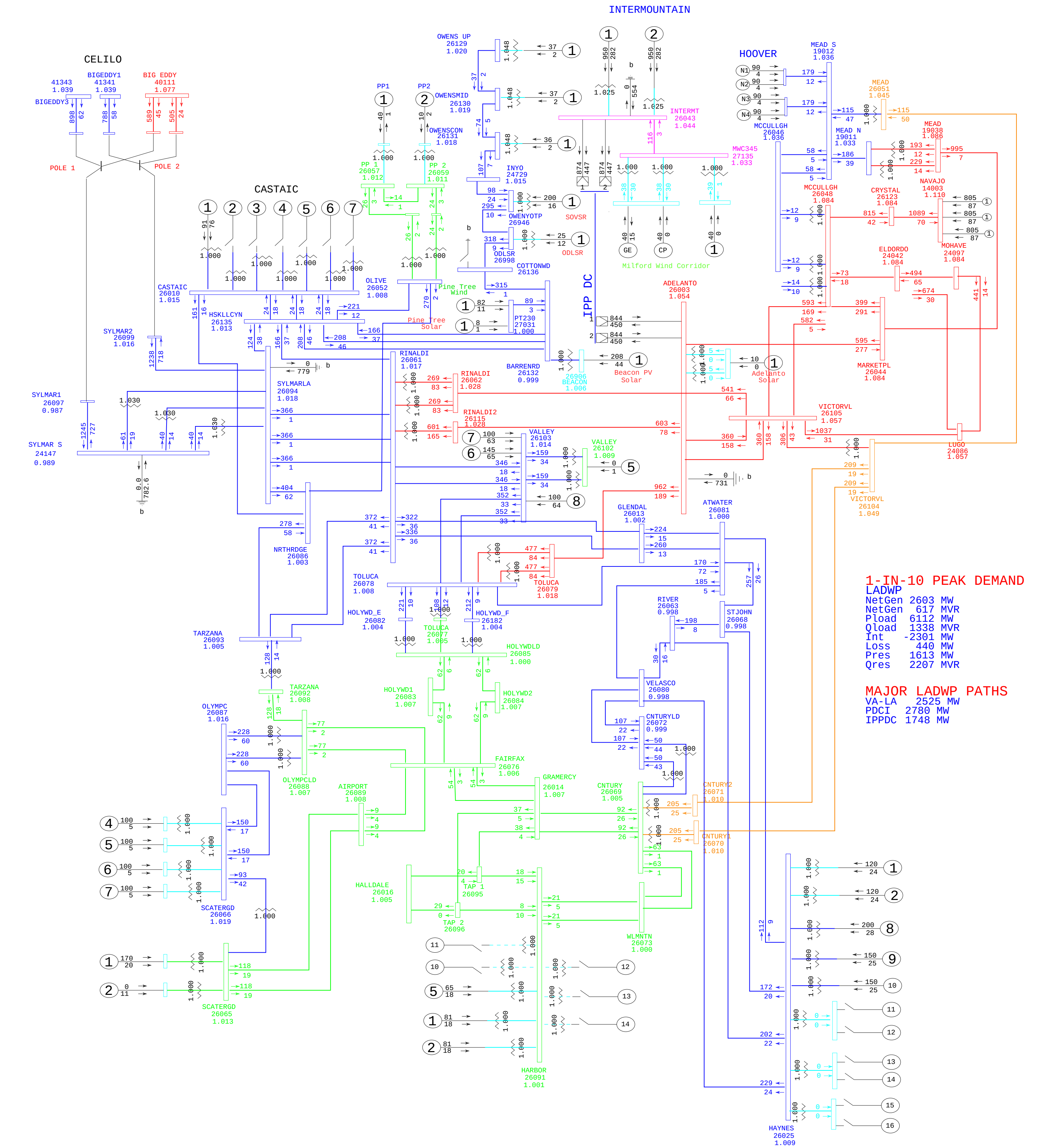
General Electric International, Inc. PSLF Program Tue Oct 25 17:45:17 2011 2011hs14.sav

WESTERN ELECTRICITY COORDINATING COUNCIL		MW/MVAR
11HS2A APPROVED OPERATING CASE		2011hs14.drw
NOVEMBER 2, 2010		Rating = 1



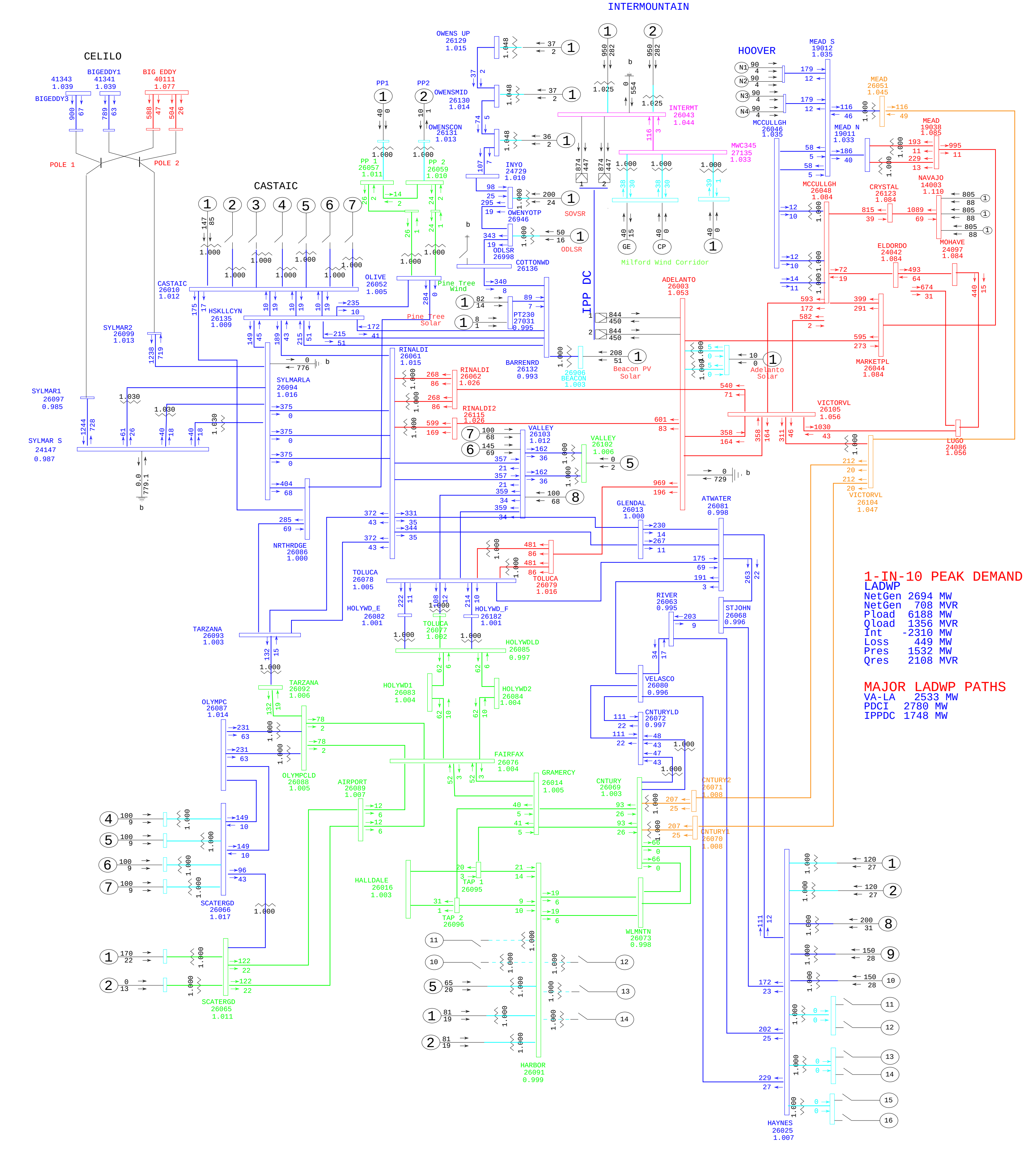
General Electric International, Inc.   PSLF Program   Tue Oct 25 17:32:13 2011   2011hs15.sav

	WESTERN ELECTRICITY COORDINATING COUNCIL 11HS2A APPROVED OPERATING CASE NOVEMBER 2, 2010	11/2/10 - 2015 DWP 1-in-10 Summer Peak	MW/MVAR 2011hs15.drw Rating = 1



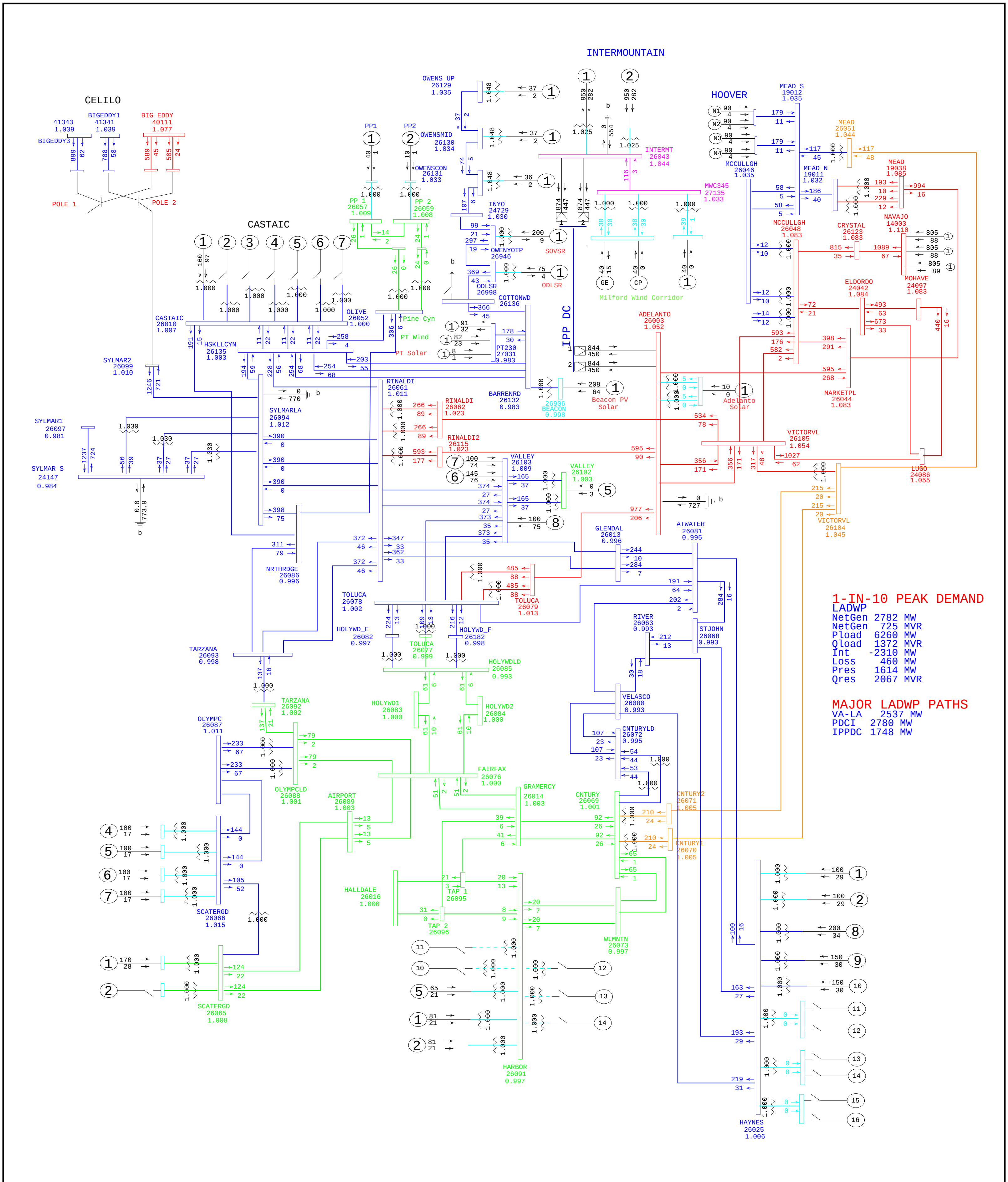
General Electric International, Inc. PSLF Program Tue Oct 25 17:51:21 2011 2011hs16.sav

	WESTERN ELECTRICITY COORDINATING COUNCIL 11HS2A APPROVED OPERATING CASE NOVEMBER 2, 2010	11/2/10 - 2016 DWP 1-in -10 Summer Peak	MW/MVAR 2011hs16.drw Rating = 1



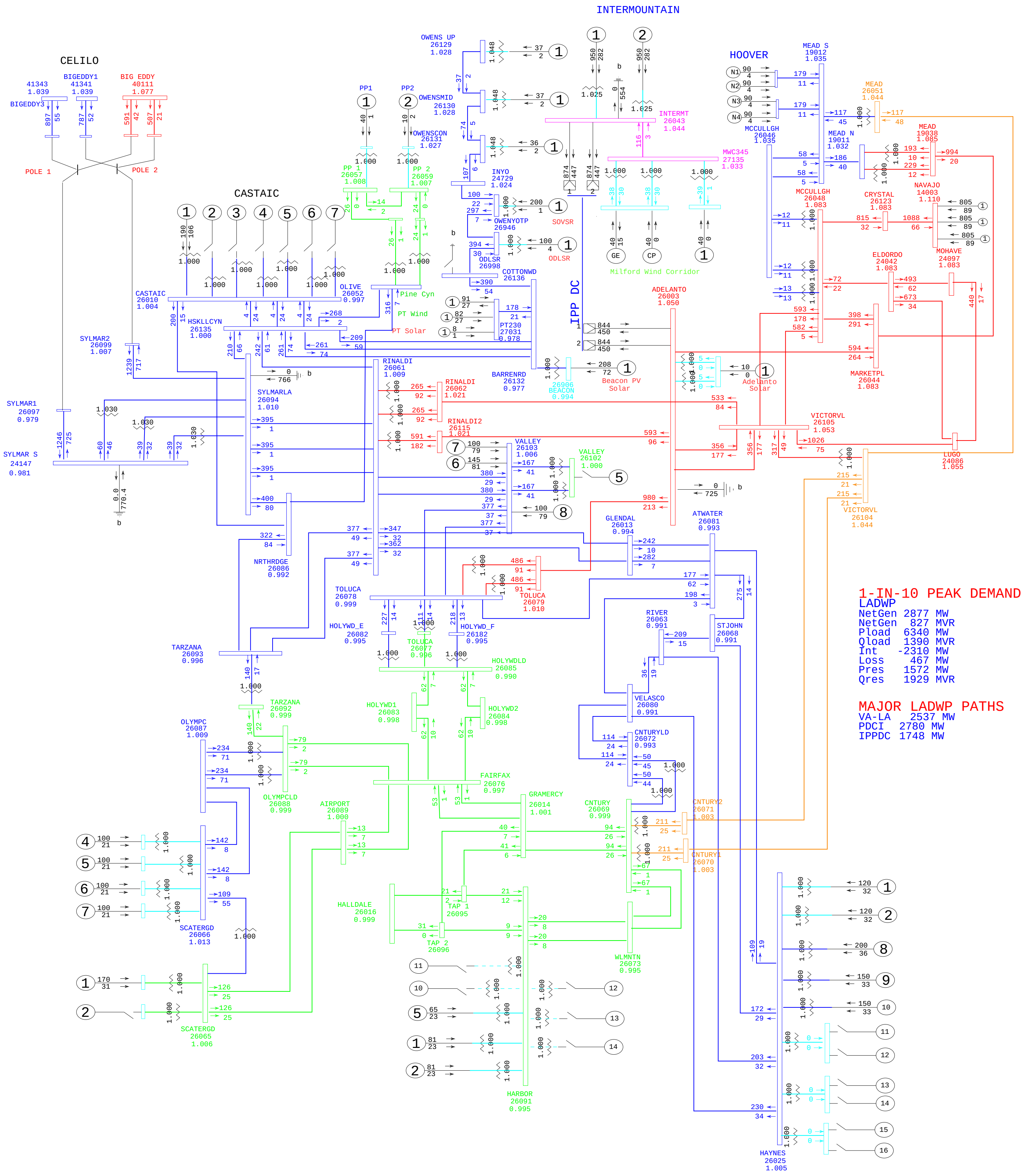
General Electric International, Inc. PSLF Program Tue Oct 25 17:55:37 2011 2011hs17.sav

	WESTERN ELECTRICITY COORDINATING COUNCIL 11HS2A APPROVED OPERATING CASE NOVEMBER 2, 2010	11/2/10 - 2017 DWP 1-in-10 Summer Peak	MW/MVAR 2011hs17.drw Rating = 1



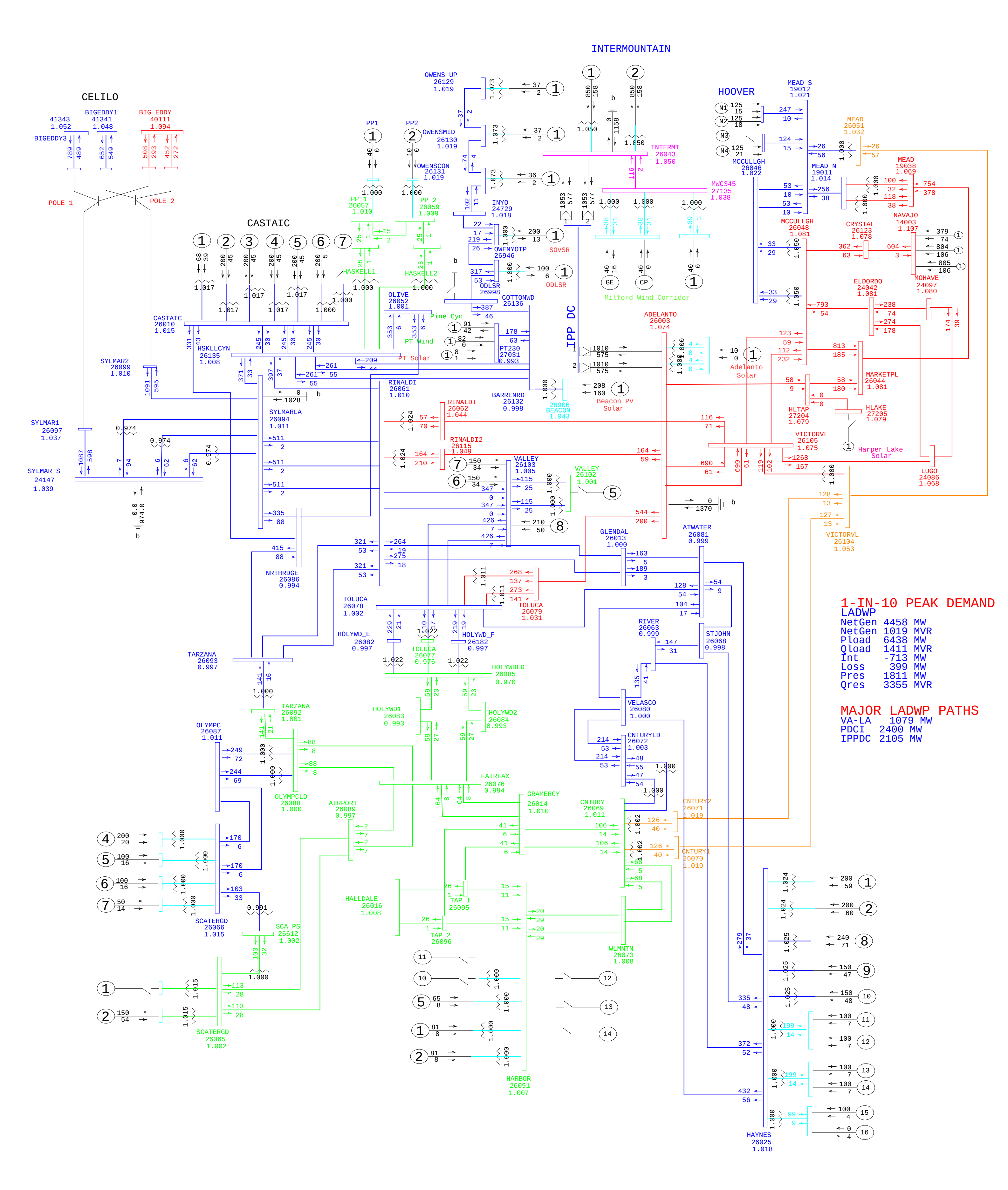
General Electric International, Inc. PSLF Program Tue Oct 25 18:11:06 2011 2011hs18.sav

	WESTERN ELECTRICITY COORDINATING COUNCIL 11HS2A APPROVED OPERATING CASE NOVEMBER 2, 2010	11/2/10 - 2018 DWP 1-in-10 Summer Peak	MW/MVAR 2011hs18.drw Rating = 1



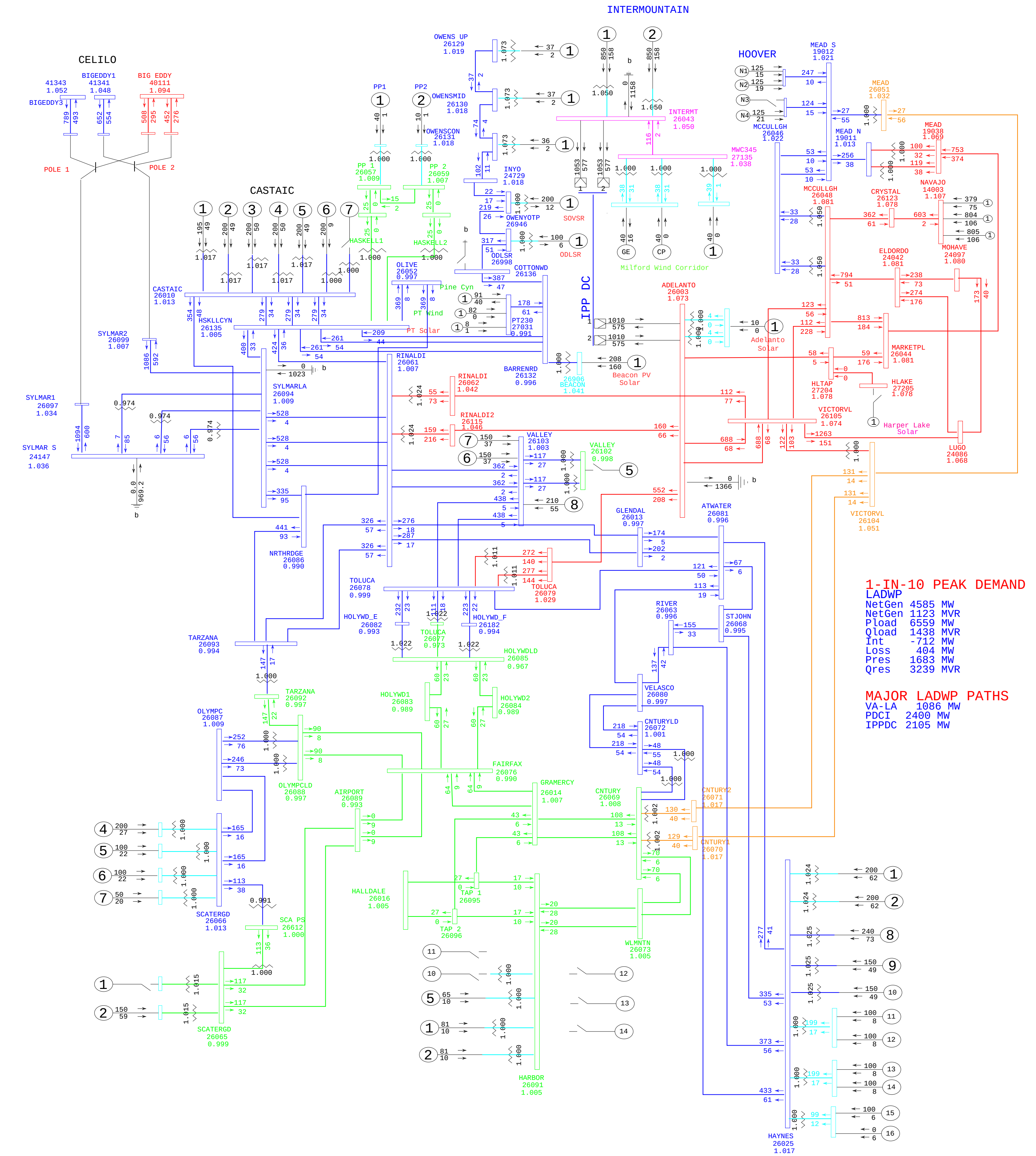
General Electric International, Inc. PSLF Program Tue Oct 25 18:13:54 2011 2011hs19.sav

	WESTERN ELECTRICITY COORDINATING COUNCIL 11HS2A APPROVED OPERATING CASE NOVEMBER 2, 2010	11/2/10 - 2019 DWP 1-in-10 Summer Peak	MW/MVAR 2011hs19.drw Rating = 1



General Electric International, Inc. PSLF Program Thu Oct 27 07:57:09 2011 2011hs20-hicastaic-ltc-hsk.sav

CALIFORNIA TRANSMISSION PLANNING GROUP		MW/MVAR
2020 - A0 FOUNDATION CASE		2011hs20.drw
08/22/11 - 2020 DWP 1-in-10 Summer Peak		Rating = 1



General Electric International, Inc. PSLF Program Thu Oct 27 07:59:12 2011 2011hs21-hicastaic-ltc-hsk.sav

CALIFORNIA TRANSMISSION PLANNING GROUP		MW/MVAR
2020 - A0 FOUNDATION CASE		2011hs21.drw
08/22/11 - 2021 DWP 1-in-10 Summer Peak		Rating = 1

Appendix F. List of Contingencies Studied

This page is intentionally left blank

Appendix F. LIST OF CONTINGENCIES STUDIED

CONT. NO.	FROM		TO		CKT
NERC CATEGORY B CONTINGENCY					
500kV Lines					
1	26003	ADELANTO	26115	RINALDI2	1
2	26003	ADELANTO	26079	TOLUCA	1
3	26044	MARKETPL	26003	ADELANTO	1
4	26044	MARKETPL	26048	MCCULLGH	1
5	26048	MCCULLGH	26105	VICTORVL	1
6	26105	VICTORVL	26003	ADELANTO	1
7	26105	VICTORVL	24086	LUGO	1
8	26105	VICTORVL	26062	RINALDI	1
287kV Lines					
9	26051	MEAD	26104	VICTORVL	1
10	26104	VICTORVL	26070	CNTURY1	1
11	26104	VICTORVL	26071	CNTURY2	1
230kV Lines					
12	26081	ATWATER	26068	STJOHN	1
13	26081	ATWATER	26080	VELASCO	1
14	26132	BARRENRD	26905	BCON230	1
15	26132	BARRENRD	26136	COTTONWD	1
16	26132	BARRENRD	26135	HSKLLCYN	2
17	26132	BARRENRD	26135	HSKLLCYN	3
18	26132	BARRENRD	26061	RINALDI	1
19	26010	CASTAIC	26035	HSKLLCYN	1
20	26010	CASTAIC	26086	NRTHRDGE	1
21	26010	CASTAIC	26052	OLIVE	1
22	26010	CASTAIC	26094	SYLMARLA	1
23	26013	GLENDAL	26081	ATWATER	1
24	26025	HAYNES	26081	ATWATER	1
25	26025	HAYNES	26063	RIVER	1
26	26025	HAYNES	26068	STJOHN	1
27	26025	HAYNES	26080	VELASCO	1
28	27031	PT230	26132	BARRENRD	1
29	26135	HSKLLCYN	26052	OLIVE	1
30	26086	NRTHRDGE	26093	TARZANA	1
31	26052	OLIVE	26086	NRTHRDGE	1
32	26061	RINALDI	26013	GLENDAL	1
33	26061	RINALDI	26135	HSKLLCYN	1
34	26061	RINALDI	26093	TARZANA	1
35	26066	SCATERGD	26087	OLYMPC	2
36	26066	SCATERGD	26087	OLYMPC	1
37	26068	STJOHN	26063	RIVER	1
38	26094	SYLMARLA	26135	HSKLLCYN	1
39	26094	SYLMARLA	26086	NRTHRDGE	1
40	26094	SYLMARLA	26061	RINALDI	1
41	26093	TARZANA	26087	OLYMPC	3
42	26078	TOLUCA	26081	ATWATER	1
43	26078	TOLUCA	26082	HOLYWD_E	1
44	26078	TOLUCA	26182	HOLYWD_F	1
45	26103	VALLEY	26061	RINALDI	1
46	26103	VALLEY	26078	TOLUCA	1
47	26080	VELASCO	26072	CNTURYLD	1
48	24729	INYO	26136	COTTONWD	1
49	26946	OWENYOTP	26136	COTTONWD	1
50	26946	OWENYOTP	24729	INYO	1
51	26946	OWENYOTP	26998	ODLSR	1
52	26998	ODLSR	26136	COTTONWD	1
138kV Lines					
53	26069	CNTURY	26014	GRAMERC1	1
54	26069	CNTURY	26014	GRAMERCY	1
55	26069	CNTURY	26073	WLMNTN	1

Appendix F. LIST OF CONTINGENCIES STUDIED

CONT. NO.	FROM		TO		CKT
56	26076	FAIRFAX	26089	AIRPORT	1
57	26076	FAIRFAX	26014	GRAMERC1	1
58	26076	FAIRFAX	26014	GRAMERCY	1
59	26076	FAIRFAX	26088	OLYMPCLD	1
60	26091	HARBOR	26073	WLMNTN	E
61	26019	HARB	26075	WLMNTNLD	A
62	26083	HOLYWD1	26076	FAIRFAX	1
63	26083	HOLYWD1	26085	HOLYWDLD	1
64	26065	SCATERGD	26089	AIRPORT	1
65	26095	TAP1	26016	HALLDALE	1
66	26096	TAP2	26016	HALLDALE	1
67	26095	TAP1	26014	GRAMERC1	1
68	26096	TAP2	26015	GRAMERC2	1
69	26095	TAP1	26014	GRAMERCY	1
70	26096	TAP2	26014	GRAMERCY	1
71	26092	TARZANA	26088	OLYMPCLD	1
72	26077	TOLUCA	26085	HOLYWDLD	2
73	26073	WLMNTN	26095	TAP1	1
74	26073	WLMNTN	26096	TAP2	1
75	26075	WLMNTNLD	26073	WLMNTN	1
76	26075	WLMNTNLD	26019	HARB	A
Auto-transformers					
77	26070	CNTURY1	26069	CNTURY	G
78	26071	CNTURY2	26069	CNTURY	F
79	26072	CNTURYLD	26069	CNTURY	E
80	26087	OLYMPC	26088	OLYMPCLD	E
81	26066	SCATERGD	26065	SCATERGD	1
82	26105	VICTORVL	26104	VICTORVL	1
NERC CATEGORY C5 CONTINGENCY					
500kV Lines					
1	26003	ADELANTO	26115	RINALDI2	1
	26105	VICTORVL	26062	RINALDI	1
2	26048	MCCULLGH	26105	VICTORVL	1
	26048	MCCULLGH	26105	VICTORVL	2
3	26105	VICTORVL	26003	ADELANTO	1
	26105	VICTORVL	26003	ADELANTO	2
4	26003	ADELANTO	26079	TOLUCA	1
	26003	ADELANTO	26044	MARKETPL	1
5	26003	ADELANTO	26105	VICTORVL	2
	26003	ADELANTO	26115	RINALDI2	1
6	26105	VICTORVL	26003	ADELANTO	1
	26105	VICTORVL	24086	LUGO	1
7	26003	ADELANTO	26105	VICTORVL	2
	26048	MCCULLGH	26105	VICTORVL	2
8	26048	MCCULLGH	26105	VICTORVL	1
	26048	MCCULLGH	24042	ELDORDO	1
345kV Lines					
9	27135	MWC345	26043	INTERMT	1
	26043	INTERMT	65995	MONA	1
287kV Lines					
10	26104	VICTORVL	26070	CNTURY1	1
	26104	VICTORVL	26071	CNTURY2	1
230kV Lines					
11	26010	CASTAIC	26135	HSKLLCYN	1
	26010	CASTAIC	26135	HSKLLCYN	2
12	26135	HSKLLCYN	26094	SYLMARLA	1
	26135	HSKLLCYN	26010	CASTAIC	1

Appendix F. LIST OF CONTINGENCIES STUDIED

CONT. NO.	FROM		TO		CKT
13	26135	HSKLLCYN	26052	OLIVE	1
	26010	CASTAIC	26135	HSKLLCYN	2
14	26135	HSKLLCYN	26061	RINALDI	1
	26010	CASTAIC	26135	HSKLLCYN	3
15	26013	GLENDAL	26081	ATWATER	1
	26013	GLENDAL	26061	RINALDI	2
16	26013	GLENDAL	26081	ATWATER	2
	26013	GLENDAL	26061	RINALDI	1
17	26103	VALLEY	26061	RINALDI	2
	26103	VALLEY	26078	TOLUCA	2
18	26132	BARRENRD	26061	RINALDI	1
	26103	VALLEY	26061	RINALDI	1
19	26094	SYLMARLA	26061	RINALDI	3
	26061	RINALDI	26093	TARZANA	1
20	26093	TARZANA	26086	NRTHRDGE	1
	26093	TARZANA	26087	OLYMPC	3
21	26013	GLENDAL	26081	ATWATER	1
	26013	GLENDAL	26081	ATWATER	2
22	26061	RINALDI	26113	GLENDAL	1
	26061	RINALDI	26113	GLENDAL	2
23	26061	RINALDI	26093	TARZANA	1
	26061	RINALDI	26093	TARZANA	2
24	26093	TARZANA	26087	OLYMPC	3
	26092	TARZANA	26088	OLYMPCLD	1
25	26103	VALLEY	26061	RINALDI	1
	26103	VALLEY	26061	RINALDI	2
26	26103	VALLEY	26078	TOLUCA	1
	26103	VALLEY	26078	TOLUCA	2
27	26080	VELASCO	26072	CNTURYLD	1
	26080	VELASCO	26072	CNTURYLD	2
28	26068	STJOHN	26063	RIVER	1
	26063	RIVER	26631	MKT A HI	A
29	26025	HAYNES	26080	VELASCO	1
	26063	RIVER	26632	MKT B HI	B
30	26063	RIVER	26080	VELASCO	1
	26063	RIVER	26633	MKT C HI	C
138kV Lines					
31	26065	SCATERGD	26089	AIRPORT	2
	26089	AIRPORT	26076	FAIRFAX	2
32	26065	SCATERGD	26089	AIRPORT	1
	26089	AIRPORT	26076	FAIRFAX	1
33	26069	CNTURY	26014	GRAMERC1	1
	26069	CNTURY	26015	GRAMERC2	1
34	26069	CNTURY	26014	GRAMERCY	1
	26069	CNTURY	26014	GRAMERCY	2
35	26069	CNTURY	26073	WLMNTN	1
	26069	CNTURY	26073	WLMNTN	2
36	26019	HARB	26075	WLMNTNLD	A
	26019	HARB	26075	WLMNTNLD	B
37	26073	WLMNTN	26091	HARBOR	D
	26073	WLMNTN	26091	HARBOR	E
38	26076	FAIRFAX	26089	AIRPORT	1
	26076	FAIRFAX	26089	AIRPORT	2
39	26076	FAIRFAX	26014	GRAMERC1	1
	26076	FAIRFAX	26015	GRAMERC2	1
40	26076	FAIRFAX	26014	GRAMERCY	1
	26076	FAIRFAX	26014	GRAMERCY	2
41	26076	FAIRFAX	26083	HOLYWD1	1
	26076	FAIRFAX	26084	HOLYWD2	1

Appendix F. LIST OF CONTINGENCIES STUDIED

CONT. NO.	FROM		TO		CKT
42	26095	TAP 1	26014	GRAMERC1	1
	26096	TAP 2	26015	GRAMERC2	1
43	26095	TAP 1	26014	GRAMERCY	1
	26096	TAP 2	26014	GRAMERCY	1
44	26073	WLMNTN	26095	TAP 1	1
	26073	WLMNTN	26096	TAP 2	1
45	26091	HARBOR	26095	TAP 1	1
	26091	HARBOR	26096	TAP 2	1
46	26016	HALLDALE	26095	TAP 1	1
	26016	HALLDALE	26096	TAP 2	1
NERC CATEGORY C2 CONTINGENCY					
500kV Lines					
1	26003	ADELANTO	26115	RINALDI2	1
	26105	VICTORVL	26003	ADELANTO	2
2	26003	ADELANTO	26079	TOLUCA	1
	26044	MARKETPL	26003	ADELANTO	1
3	26105	VICTORVL	26003	ADELANTO	1
	24086	LUGO	26105	VICTORVL	1
4	26105	VICTORVL	26003	ADELANTO	2
	26048	MCCULLGH	26105	VICTORVL	2
5	26048	MCCULLGH	26105	VICTORVL	1
	24042	ELDORDO	26048	MCCULLGH	1
6	14003	NAVAJO	26123	CRYSTAL	1
	26123	CRYSTAL	26048	MCCULLGH	1
345kV Lines					
7	27135	MWC345	26043	INTERMT	1
	26043	INTERMT	65995	MONA	1
230kV Lines					
8	26010	SYLMARLA	26135	HSKLLCYN	1
	26010	CASTAIC	26135	HSKLLCYN	1
9	26135	HSKLLCYN	26052	OLIVE	1
	26010	CASTAIC	26135	HSKLLCYN	2
10	26135	HSKLLCYN	26061	RINALDI	1
	26010	CASTAIC	26135	HSKLLCYN	3
11	26081	ATWATER	26013	GLENDAL	1
	26061	RINALDI	26013	GLENDAL	2
12	26081	ATWATER	26013	GLENDAL	2
	26061	RINALDI	26013	GLENDAL	1
13	26103	VALLEY	26061	RINALDI	2
	26103	VALLEY	26078	TOLUCA	2
14	26094	SYLMARLA	26061	RINALDI	3
	26010	CASTAIC	26094	SYLMARLA	1
15	26094	SYLMARLA	26061	RINALDI	3
	26061	RINALDI	26093	TARZANA	1
16	26086	NRTHRDGE	26093	TARZANA	1
	26093	TARZANA	26087	OLYMPIC	3
17	26068	STJOHN	26063	RIVER	1
	26063	RIVER	26631	MKT "A"	A
18	26025	HAYNES	26063	RIVER	1
	26063	RIVER	26632	MKT "B"	B
19	26063	RIVER	26080	VELASCO	1
	26063	RIVER	26633	MKT "C"	C
20	26132	BARRENRD	26061	RINALDI	1
	24729	INYO	26132	BARRENRD	1
21	26132	BARRENRD	26061	RINALDI	1
	26103	VALLEY	26061	RINALDI	1
22	26065	SCATERGD	26089	AIRPORT	2
	26089	AIRPORT	26076	FAIRFAX	2
23	26065	SCATERGD	26089	AIRPORT	1
	26089	AIRPORT	26076	FAIRFAX	1

Appendix G. Switching Sequences for Transient and Post-Transient

This page is intentionally left blank

SWITCHING SEQUENCES

CONTINGENCY	SEQUENCE
Adelanto-Rinaldi 500kV Line	1
Adelanto - Toluca 500 kV Line	2
Adelanto - Victorville 500 kV Line	3
Lugo-Victorville 500 kV Line	4
Victorville-Rinaldi 500 kV Line	5
McCullgh-Victorville 500 kV Line	6
Mead – Victorville 287 kV Line	7
Cottonwood-Barren Ridge 230 kV with Remedial Action Scheme (RAS)	8
Rinaldi – Barren Ridge 230 kV	9
PDCI Bipole	10
IPP DC Bipole	11
Palo Verde-g2-OL-MA-RAS	12
Adelanto-Rinaldi and Victorville-Rinadi 500kV Lines	13
McCullgh-Victorville 500 kV Lines 1 & 2	14
Victorville-Century 287 kV Lines 1 & 2	15
Rinaldi - Tarzana 230 kV Lines 1 & 2	16
Rinaldi-Glendale 230 kV Lines 1&2	17
Rinaldi-Valley 230 kV Lines 1 & 2	18
Toluca-Valley 230 kV Lines 1&2	19
Glendale-Atwater 230 kV Lines 1&2	20
Tarzana – Olympic 230kV and 138kV Lines	21
Velasco-Century 230kV Lines 1&2	22
Century - Wilmington 138 kV Lines 1&2	23
Gramercy – Fairfax 138 kV Lines 1 & 2	24
Century – Gramercy 138 kV Lines 1 & 2	25
Gramercy Tap1 & Tap2 138 kV Lines	26
Airport – Fairfax 138 kV Lines 1 & 2	27
Barren Ridge – Haskell 230kV Lines 1 & 2	28
Toluca – Hollywood Lines 1, 2 and 3	29
Rinaldi – Tarzana Lines 1 & 2 and Northridge – Tarzana Line 1	30
Rinaldi – Tarzana Lines 1 & 2 and Northridge – Tarzana Line 1 with RAS	31

Adelanto-Rinaldi 500kV Line 1

```
RUN
*   3 phase 4 cycle fault at Adelanto
*   Loss of Adelanto-Rinaldi 500kV line
*
*  CC cards for post-transient only
*
*   Fault bus at RINALDI 500 busses
FB   0.0 "RINALDI2" 500.
*
*  Temporary block all DC
*
DDC   0.0 "INT MT1R"  206. "ADELAN1I" 202.
DDC   0.0 "CELILO1 "  500. "SYLMAR1 " 230.
DDC   0.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*   Clear fault at Rinaldi
CFB  4.0 "RINALDI2" 500.
*
*   Trip Adelanto - Rinaldi  500kV line
*
DL   4.0 "ADELANTO" 500. "RINALDI2" 500. "1 "
*
*  Restart all DC
*
SDC   4.0 "INT MT1R"  206. "ADELAN1I" 202.
SDC   4.0 "CELILO1 "  500. "SYLMAR1 " 230.
SDC   4.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*  Readjust Northwest SVC's
CC  MSV  0.0 "KEEL-SVC" 230.0 "1 "  350. -300.
CC  MSV  0.0 "MV-SVC  " 230.0 "1 "  350. -300.
*
*  Add SVC's at Marketplace and Adelanto
*
CC MBS  120.0 "ADELSVC " 500. "sv" "A" 0.0 1.320
CC MBS  120.0 "MKTPSVC " 500. "sv" "A" 0.0 1.320
*
```

Adelanto - Toluca 500 kV Line 2

```
RUN
*   3 phase 4 cycle fault at Adelanto
*   Loss of Adelanto-Toluca Line
*  CC cards for post-transient only
*
*   Fault bus at Adelanto
FB   0.0 "ADELANTO" 500.
*
*  Temporary block all DC
*
DDC   0.0 "INT MT1R"  206. "ADELAN1I" 202.
```

```
DDC   0.0 "CELILO1 "  500. "SYLMAR1 " 230.
DDC   0.0 "CELILO2 "  500. "SYLMAR2 " 230.
*   Clear fault at Adelanto
CFB  4.0 "ADELANTO" 500.
*
*   Trip Adelanto - Toluca 500kV line
*
DL   4.0 "ADELANTO" 500. "TOLUCA  " 500. "1 "
*
*  Restart all DC
*
SDC   4.0 "INT MT1R"  206. "ADELAN1I" 202.
SDC   4.0 "CELILO1 "  500. "SYLMAR1 " 230.
SDC   4.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*  Readjust Northwest SVC's
* CC  MSV  0.0 "KEEL-SVC" 230.0 "1 "  350. -300.
* CC  MSV  0.0 "MV-SVC  " 230.0 "1 "  350. -300.
*
*  Add SVC's at Marketplace and Adelanto
*
CC MBS  120.0 "ADELSVC " 500. "sv" "A" 0.0 1.320
CC MBS  120.0 "MKTPSVC " 500. "sv" "A" 0.0 1.320
*
```

Adelanto - Victorville 500 kV Line 3

```
RUN
*   3 phase 4 cycle fault at Victorville
*   Loss of Adelanto-Victorville one line
*  CC cards for post-transient only
*
*   Fault bus at Victorville
FB   0.0 "VICTORVL" 500.
*
*  Temporary block all DC
*
DDC   0.0 "INT MT1R"  206. "ADELAN1I" 202.
DDC   0.0 "CELILO1 "  500. "SYLMAR1 " 230.
DDC   0.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*   Clear fault at Victorville
CFB  4.0 "VICTORVL" 500.
*
*   Trip Adelanto - Victorville line 1
*
DL   4.0 "ADELANTO" 500. "VICTORVL" 500. "1 "
*
*  Restart all DC
*
SDC   4.0 "INT MT1R"  206. "ADELAN1I" 202.
SDC   0.0 "CELILO1 "  500. "SYLMAR1 " 230.
SDC   0.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*  Readjust Northwest SVC's
```

```
CC  MSV  0.0 "KEEL-SVC" 230.0 "1 "  350. -300.
CC  MSV  0.0 "MV-SVC  " 230.0 "1 "  350. -300.
*  Add SVC's at Marketplace and Adelanto
*
*  CC  MBS  120.0 "ADELSVC " 500. "sv" "A" 0.0 1.320
*  CC  MBS  120.0 "MKTPSVC " 500. "sv" "A" 0.0 1.320
*
```

Lugo-Victorville 500 kV Line 4

```
RUN
*   3 phase 4 cycle fault at Lugo
*   Loss of Lugo-Victorville Line
*   CC cards for post-transient only
*
*   Fault bus at Lugo
FB   0.0 "LUGO    " 500.
*
*  Temporary block all DC
*
DDC   0.0 "INT MT1R"  206. "ADELAN1I" 202.
DDC   0.0 "CELILO1 "  500. "SYLMAR1 " 230.
DDC   0.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*   Clear fault at Lugo
CFB  4.0 "LUGO    " 500.
*
*   Trip Lugo - Victorville line
*
DL   4.0 "LUGO    " 500. "VICTORVL " 500. "1 "
*
*  Restart all DC
*
SDC   4.0 "INT MT1R"  206. "ADELAN1I" 202.
SDC   0.0 "CELILO1 "  500. "SYLMAR1 " 230.
SDC   0.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*  Readjust Northwest SVC's
CC  MSV  0.0 "KEEL-SVC" 230.0 "1 "  350. -300.
CC  MSV  0.0 "MV-SVC  " 230.0 "1 "  350. -300.
*
*  Add SVC's at Marketplace and Adelanto
*
CC  MBS  120.0 "ADELSVC " 500. "sv" "A" 0.0 1.320
CC  MBS  120.0 "MKTPSVC " 500. "sv" "A" 0.0 1.320
*
```

Victorville-Rinaldi 500 kV Line 5

```
RUN
*   3 phase 4 cycle fault at Adelanto
*   Loss of Victorville-Rinadi 500 kV Line
*  CC cards for post-transient only
*
*   Fault bus at RINALDI 500 busses
```

```
FB   0.0 "RINALDI " 500.
*
*  Temporary block all DC
*
DDC   0.0 "INT MT1R"  206. "ADELAN1I" 202.
DDC   0.0 "CELILO1 "  500. "SYLMAR1 " 230.
DDC   0.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*   Clear fault at Rinaldi
CFB  4.0 "RINALDI " 500.
*
*   Trip Adelanto - Rinaldi 500 kV Line
*
DL   4.0 "VICTORVL" 500. "RINALDI " 500. "1 "
*
*  Restart all DC
*
SDC   4.0 "INT MT1R"  206. "ADELAN1I" 202.
SDC   4.0 "CELILO1 "  500. "SYLMAR1 " 230.
SDC   4.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*  Readjust Northwest SVC's
CC  MSV  0.0 "KEEL-SVC" 230.0 "1 "  350. -300.
CC  MSV  0.0 "MV-SVC  " 230.0 "1 "  350. -300.
*
*
*  Add SVC's at Marketplace and Adelanto
*
CC  MBS  120.0 "ADELSVC " 500. "sv" "A" 0.0 1.320
CC  MBS  120.0 "MKTPSVC " 500. "sv" "A" 0.0 1.320
*
```

McCullgh-Victorville 500 kV Line 6

```
RUN
*   3 phase 4 cycle fault at Victorville
*   Loss of McCullgh-Victorville one line
*  CC cards for post-transient only
*
*   Fault bus at Victorville
FB   0.0 "VICTORVL" 500.
*
*  Temporary block all DC
*
DDC   0.0 "INT MT1R"  206. "ADELAN1I" 202.
DDC   0.0 "CELILO1 "  500. "SYLMAR1 " 230.
DDC   0.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*   Clear fault at Victorville
CFB  4.0 "VICTORVL" 500.
*
*   Trip McCullough - Victorville lines
*
DL   4.0 "MCCULLGH" 500. "VICTORVL" 500. "1 "
*
*  Restart all DC
```

```
*
SDC   4.0 "INT MT1R"  206. "ADELAN1I" 202.
SDC   4.0 "CELILO1 "  500. "SYLMAR1 " 230.
SDC   4.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*  Readjust Northwest SVC's
CC  MSV  0.0 "KEEL-SVC" 230.0 "1 "  350. -300.
CC  MSV  0.0 "MV-SVC  " 230.0 "1 "  350. -300.
*
*  Add SVC's at Marketplace and Adelanto
*
CC  MBS  120.0 "ADELSVC " 500. "sv" "A" 0.0 1.320
CC  MBS  120.0 "MKTPSVC " 500. "sv" "A" 0.0 1.320
*
```

Mead-Victorville 287 kV Line 7

```
RUN
*   3 phase 4 cycle fault at Mead
*   Loss of Mead-Victorville one line
*  CC cards for post-transient only
*
*   Fault bus at Mead
FB   0.0 "MEAD" 287.
*
*   Clear fault at Mead
CFB  4.0 "MEAD" 287.
*
*   Trip Mead - Victorville lines
*
DL   4.0 "MEAD" 287. "VICTORVL" 287. "1 "
*

*  Readjust Northwest SVC's
CC  MSV  0.0 "KEEL-SVC" 230.0 "1 "  350. -300.
CC  MSV  0.0 "MV-SVC  " 230.0 "1 "  350. -300.
*
*  Add SVC's at Marketplace and Adelanto
*
CC  MBS  120.0 "ADELSVC " 500. "sv" "A" 0.0 1.320
CC  MBS  120.0 "MKTPSVC " 500. "sv" "A" 0.0 1.320
*
```

Cottonwood-Barren Ridge 230 kV Line with RAS 8

```
RUN
*   Cottonwood - Barren Ridge 230kV Line Out
*   W/ RAS
*   3-phase 4 cycle fault at Barren Ridge
*
* CC  DRP 110
*
*   Fault bus at Barren Ridge 230
FB  0.0  "BARRENRD" 230.
*
*
```

```
*   Clear fault bus Barren Ridge
CFB 4.0  "BARRENRD" 230.
*
*   Trip Cottonwood - Barren Ridge
DL  4.0  "COTTONWD" 230. "BARRENRD" 230. "1 "
*
*   Trip OG Units
*
TG  8.0  "OWENS UP " 11.5  "1 "
TG  8.0  "OWENSMID " 11.5  "1 "
TG  8.0  "OWENSCON " 11.5. "1 "
*
*
* Open Inyo tie
*
DL  12.0  "INYO    " 115. "INYO PS " 115. "1 "
*
```

Barren Ridge - Rinaldi 230 kV Line 9

```
RUN
*   Barren Ridge-Rinaldi 230kV Line Out
*
*   3-phase 4 cycle fault at Barren Ridge
*
*
*   Fault bus at Barren Ridge 230
FB  0.0  "BARRENRD" 230.
*
*
*
*   Clear fault bus at BARRENRD
CFB 4.0  "BARRENRD" 230.
*
*   Trip Barren Ridge - Rinaldi
DL  4.0  "RINALDI" 230. "BARRENRD" 230. "1 "
```

PDCI Bipole 10

```
RUN
*      Loss of PDCI Bipole with North-to-South flow
*      for Multi-terminal DC Presentation
*
*   CC cards for post-transient only
*
CC  DRP 2700
*
*   Readjust Northwest SVC's
*
CC  MSV 0.0 "KEEL-SVC" 19.60 "1 "  350. -300.
CC  MSV 0.0 "MV-SVC  " 19.60 "1 "  350. -300.
*
*   Deactivate PDCI
*
DDC   0.0 "CELILO3P"  500. "SYLMAR3P" 500.
DDC   0.0 "CELILO4P"  500. "SYLMAR4P" 500.
```

```
DDC   0.0 "dc41311 "  500. "CELILO3P" 500.
DDC   0.0 "dc41313 "  500. "CELILO3P" 500.
DDC   0.0 "dc26097 "  500. "SYLMAR3P" 500.
DDC   0.0 "dc41312 "  500. "CELILO4P" 500.
DDC   0.0 "dc41314 "  500. "CELILO4P" 500.
DDC   0.0 "dc26099 "  500. "SYLMAR4P" 500.
*
*   Switching off all Sylmar Filter and Shunt Banks
*
CC  MBS  4.5 "SYLMARLA"  230.    "b "  "C" 0.0 0.00
CC  MBS  4.5 "SYLMAR S"  230.    "b "  "C" 0.0 0.00
*
CC  MSV 6.0 "DEVRSVC1" 500.0 "1 "  549. -100.
*
*   Drop filter bank capacitors at Celilo (BPA RAS does not do this anymore - 10/1/02)
*
*  MBS  120.0 "CELILO1"  500.    "b "  "C" 0.0 1.27
*  MBS  120.0 "CELILO2"  500.    "b "  "C" 0.0 1.27
*  MBS  120.0 "CELILO3"  230.    "b "  "C" 0.0 2.36
*  MBS  120.0 "CELILO4"  230.    "b "  "C" 0.0 2.36
*
*   This routine will call the FACRI (Fort Rock and Malin MSC)
*   in In-Run EPCL (facri.p) and will be done at 17.5 cycles
*
*   Insert Fort Rock series caps
CC  RC  12.6 "CAPTJACK" 500. "GRIZZLY " 500. "1 " 4
CC  RC  12.6 "GRIZZLY " 500. "MALIN   " 500. "2 " 4
CC  RC  12.6 "PONDROSA" 500. "SUMMER L" 500. "1 " 4
*
*   Remove shunt reactor from Malin bus
CC  MSV  13.4 "MALIN   " 500. "s " 0.0 0.0
CC  MBS  13.4 "MALIN   " 500. "r3" "D"
CC  MBS  13.4 "MALIN   " 500. "r4" "D"
*
*   Switch on Shunt caps at malin as part of FACRI
CC  MBS  13.4 "MALIN   " 500. "c1" "R"
CC  MBS  13.4 "MALIN   " 500. "c2" "R"
*
*   Remove reactors at Olinda
*
CC  MLS 17.5 "OLINDA  " 500. "MAXWELL " 500. "1 " 1 "D" "f "
CC  MLS 17.5 "CAPTJACK" 500. "OLINDA  " 500. "1 " 3 "D" "f "
*
*   Remove reactors at Tracy
*
CC  MLS 17.5 "MAXWELL " 500. "TRACY   " 500. "1 " 2 "D" "t "
*
*   Insert capacitors at Olinda and Tracy
*
CC  MBS   17.5 "OLINDA"   500.    "c1"  "R"
*
CC  MBS   17.5 "TRACY"    500.    "c1"  "R"
CC  MBS   17.5 "TRACY"    500.    "c2"  "R"
CC  MBS   17.5 "TRACY"    500.    "c3"  "R"
CC  MBS   17.5 "TRACY"    500.    "c4"  "R"
*
```

```
*   Switch on Table Mountain Shunt cap
*   2 x 217 caps (91 Mvar reactor modeled separately)
CC  MBS  90. "TABLE MT" 500. "c1" "R"
CC  MBS  90. "TABLE MT" 500. "c2" "R"
*
*******************************************************
*   Drop Northwest Generation (2700 MW for COI and PDCI)
*******************************************************
*
*   CHIEF J5 = 900 (100 MW X 9 Units) - check the case to ensure the MW amount !!!
TG   21.7 "CHJ 1718"   13.8 "17"
TG   21.7 "CHJ 1718"   13.8 "18"
TG   21.7 "CHJ 1920"   13.8 "19"
TG   21.7 "CHJ 1920"   13.8 "20"
TG   21.7 "CHJ 2122"   13.8 "21"
TG   21.7 "CHJ 2122"   13.8 "22"
TG   21.7 "CHJ 2324"   13.8 "23"
TG   21.7 "CHJ 2324"   13.8 "24"
TG   21.7 "CHJ 25"     13.8 "25"
* TG   21.7 "CHJ 2627"   13.8 "26"
* TG   21.7 "CHJ 2627"   13.8 "27"
*
*   CHIEF JO = 600 (75.0 MW X 8 Units)
*   TG   21.7 "CHIEF JO"    13.8 "**"
*
*   CHIEF J2 = 600 (75 MW X 8 Units)
*   TG   21.7 "CHIEF J2"    13.8 "**"
*
*   COULEE19 = 600
TG   25.9 "COULEE19 "   15.0 "**"
*
*   COULEE20 = 600
TG   25.9 "COULEE20 "   15.0 "**"
*
*   COULEE21 = 600
TG   25.9 "COULEE21"   15.0 "**"
*
*   COULEE22 = SWING BUS
*   TG   25.9 "COULEE22 "   15.0 "**"
*
*   COULEE23 = OFF-LINE
*   TG   25.9 "COULEE23 "   15.0 "**"
*
*   COULEE24 = 700
*   TG   25.9 "COULEE24 "   15.0 "**"
*
*
*  Add SVC's at Marketplace and Adelanto
*
CC  MBS  120.0 "ADELSVC " 500. "sv" "A" 0.0 1.320
CC  MBS  120.0 "MKTPSVC " 500. "sv" "A" 0.0 1.320
*
*  Remove Big Eddy 230 kV bs shunt per Jim Gronquist Email 03/10/08 at 11:36 am
*
CC  MSV  13.4 "BIGEDDY2" 230. "s " 0.0 0.0
*
```

```
*   Insert capacitors at Vaca-Dixon, Tesla, and Metcalf 230 kV buses
*
CC   MBS   90.0 "VACA-DIX"   230.    "c1"  "R"
CC   MBS   90.0 "VACA-DIX"   230.    "c2"  "R"
*
CC   MBS   90.0 "NEWARK D"   230.    "c1"  "R"
CC   MBS   90.0 "NEWARK D"   230.    "c2"  "R"
*
CC   MBS   90.0 "TESLA D "   230.    "c1"  "R"
CC   MBS   90.0 "TESLA D "   230.    "c2"  "R"
CC   MBS   90.0 "TESLA D "   230.    "c3"  "R"
CC   MBS   90.0 "TESLA D "   230.    "c4"  "R"
*
```

IPP DC Bipole 11

```
RUN
*      Loss of IPP Bipole with North-to-South flow
*
*  CC cards for post-transient only
*
CC  DRP 1900
*
*   Readjust Northwest SVC's
*
CC  MSV 0.0 "KEEL-SVC" 19.60 "1 "  350. -300.
CC  MSV 0.0 "MV-SVC  " 19.60 "1 "  350. -300.
*
*   Readjust SCE SVC's
*
MSV 0.0 "DEVRSVC1" 500.0 "1 "  400. -249.
*
*  Delete Intermountain and Adelanto buses
*
DDC  0.0 "INT MT1R"  206. "ADELAN1I" 202.
*
*  Drop filter bank capacitors at Intermountain
*
MBS  4.0 "INTERMT "  345.    "b "  "D"
*
*  Drop filter bank capacitors at Adelanto
*
MBS  4.0 "ADELANTO"  500.    "b "  "D"
*
*  Trip both units at Intermountain
*
TG  10.2 "INTERM1G "  26.0  "1 "
TG  10.2 "INTERM2G "  26.0  "2 "
*
*  Trip all wind turbines
*
TG  10.2 "WTGGE   "  0.57  "1 "
TG  10.2 "WTGCP   "  0.69  "1 "
TG  10.2 "WTGGE2  "  0.57  "1 "
*
```

```
MBS  10.2 "MWC1_35 "  34.5    "b "  "D"
MBS  10.2 "MWC2_35 "  34.5    "b "  "D"
*
*
*  Add SVC's at Marketplace and Adelanto
*
CC  MBS  120.0 "ADELSVC " 500. "sv" "A" 0.0 1.320
CC  MBS  120.0 "MKTPSVC " 500. "sv" "A" 0.0 1.320
*
```

Loss of Two Palo Verde Units 12

```
RUN
*   Loss of 2 Palo Verde generators
*
*  CC cards for post-transient only
*
*  Set Generator MW Dropping
CC  DRP 2641
*
*   Readjust Northwest SVC's
*
CC  MSV 0.0 "KEEL-SVC" 19.60 "1 "  350. -300.
CC  MSV 0.0 "MV-SVC  " 19.60 "1 "  350. -300.
*   CC  RG  0.0 "DALLES 3"  13.8 "1 "  180. -270.
*
*  Trip Palo Verde units #1 and #3
*
TG   0.0 "PALOVRD1"  24. "**"
TG   0.0 "PALOVRD2"  24. "**"
*
*
*   This routine will call the FACRI (Fort Rock and Malin MSC)
*      in In-Run EPCL (facri.p)
*   Disregard timing
*
*   Insert Fort Rock series caps
CC  RC 12.6 "CAPTJACK" 500. "GRIZZLY " 500. "1 " 4
CC  RC 12.6 "GRIZZLY " 500. "MALIN   " 500. "2 " 4
CC  RC 12.6 "PONDROSA" 500. "SUMMER L" 500. "1 " 4
*
*   Switch on Shunt caps at malin as part of FACRI
CC  MBS 13.4 "MALIN   " 500. "c1" "R"
CC  MBS 13.4 "MALIN   " 500. "c2" "R"
*CC  MBS 13.4 "MALIN   " 500. "r3" "D"
*CC  MBS 13.4 "MALIN   " 500. "r4" "D"
CC  MSV 13.4 "MALIN   " 500. "s " 0.0 0.0
*
*  Load shed in the Arizona Area (2-PV RAS)
*
* Total Load Drop = 120
* 120.0 + J3.89
*
MBL   60.0   "AGUAFAPS"   69.   "AP"  "M"  -15.0  -2.72
MBL   60.0   "PAPAGOBT"   69.   "SR"  "M"  -30.0  -3.80
MBL   60.0   "SANTAN  "   69.   "SR"  "M"  -30.0  -0.10
MBL   60.0   "CORBELRS"   69.   "SR"  "M"  -15.0  -0.80
```

```
MBL   60.0   "ORME  RS"   69.   "SR"  "M"  -15.0  -0.22
MBL   60.0   "THUNDRST"   69.   "SR"  "M"  -15.0  -0.05
*
*
*   Remove reactors at Olinda
*
CC  MLS 17.5 "OLINDA"   500. "MAXWELL" 500. "1 " 1 "D" "f "
CC  MLS 17.5 "CAPTJACK" 500. "OLINDA"  500. "1 " 4 "D" "t "
*
*   Switch on Olinda Shunt cap
*
CC  MBS  17.5 "OLINDA  " 500. "c1" "R"
*
*   Switch on Table Mountain Shunt cap
*   2 x 217 caps (91 Mvar reactor modeled separately)
CC  MBS  90. "TABLE MT" 500. "c1" "R"
CC  MBS  90. "TABLE MT" 500. "c2" "R"
*
*
```

Adelanto-Rinaldi and Victorville-Rinadi 500kV Lines 13

```
RUN
*   3 phase 4 cycle fault at Adelanto
*   Loss of Adelanto-Rinaldi and Victorville-Rinadi 500kV lines
*  CC cards for post-transient only
*
*   Fault bus at RINALDI 500 busses
FB   0.0 "RINALDI " 500.
FB   0.0 "RINALDI2" 500.
*
*
*  Temporary block all DC
*
DDC   0.0 "INT MT1R"  206. "ADELAN1I" 202.
DDC   0.0 "CELILO1 "  500. "SYLMAR1 " 230.
DDC   0.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*   Clear fault at Rinaldi
CFB  4.0 "RINALDI " 500.
CFB  4.0 "RINALDI2" 500.
*
*   Trip Adelanto - Rinaldi & Victorville-Rinaldi 500kV lines
*
DL   4.0 "ADELANTO" 500. "RINALDI2" 500. "1 "
DL   4.0 "VICTORVL" 500. "RINALDI " 500. "1 "
*
*  Restart all DC
*
SDC   4.0 "INT MT1R"  206. "ADELAN1I" 202.
SDC   4.0 "CELILO1 "  500. "SYLMAR1 " 230.
SDC   4.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*
*
*  Readjust Northwest SVC's
CC  MSV  0.0 "KEEL-SVC" 230.0 "1 "  350. -300.
```

```
CC  MSV  0.0 "MV-SVC  " 230.0 "1 "  350. -300.
*
*
*  Add SVC's at Marketplace and Adelanto
*
CC MBS  120.0 "ADELSVC " 500. "sv" "A" 0.0 1.320
CC MBS  120.0 "MKTPSVC " 500. "sv" "A" 0.0 1.320
```

McCullgh-Victorville 500 kV Lines 1 & 2 14

```
RUN
*   3 phase 4 cycle fault at Victorville
*   Loss of McCullgh-Victorville two lines
*   CC cards for post-transient only
*
*   Fault bus at Victorville
FB   0.0 "VICTORVL" 500.
*
*
*  Temporary block all DC
*
DDC   0.0 "INT MT1R"  206. "ADELAN1I" 202.
DDC   0.0 "CELILO1 "  500. "SYLMAR1 " 230.
DDC   0.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*   Flash series capacitors in following 500 kV Lines
*
FC   0.0 "MARKETPL" 500. "ADELANTO" 500. "1 " 1
FC   0.0 "MOHAVE  " 500. "LUGO    " 500. "1 " 1
FC   0.0 "ELDORDO" 500.  "LUGO    " 500. "1 " 3
FC   0.0 "MCCULLGH" 500. "VICTORVL" 500. "1 " 3
FC   0.0 "MCCULLGH" 500. "VICTORVL" 500. "2 " 1
*
*   Clear fault at Victorville
CFB  4.0 "VICTORVL" 500.
*
*   Trip McCullough - Victorville lines
*
DL   4.0 "MCCULLGH" 500. "VICTORVL" 500. "1 "
DL   4.0 "MCCULLGH" 500. "VICTORVL" 500. "2 "
*
*  Restart all DC
*
SDC   4.0 "INT MT1R"  206. "ADELAN1I" 202.
SDC   4.0 "CELILO1 "  500. "SYLMAR1 " 230.
SDC   4.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*   Reinsert series capacitors in following 500 kV Lines
*
RC   4.0 "MARKETPL" 500. "ADELANTO" 500. "1 " 1
RC   8.0 "MOHAVE  " 500. "LUGO    " 500. "1 " 1
RC   8.0 "ELDORDO" 500.  "LUGO    " 500. "1 " 3
RC   8.0 "MCCULLGH" 500. "VICTORVL" 500. "1 " 1
RC   8.0 "MCCULLGH" 500. "VICTORVL" 500. "1 " 3
RC   8.0 "MCCULLGH" 500. "VICTORVL" 500. "2 " 1
```

```
RC   8.0 "MCCULLGH" 500. "VICTORVL" 500. "2 " 3
*
*  Readjust Northwest SVC's
CC  MSV  0.0 "KEEL-SVC" 230.0 "1 "  350. -300.
CC  MSV  0.0 "MV-SVC  " 230.0 "1 "  350. -300.
*
*  Add SVC's at Marketplace and Adelanto
*
CC  MBS  120.0 "ADELSVC " 500. "sv" "A" 0.0 1.320
CC  MBS  120.0 "MKTPSVC " 500. "sv" "A" 0.0 1.320
*
```

Victorville – Century 287 kV Lines 1 & 2 15

```
RUN
*   3 phase 4 cycle fault at Victorville
*   Loss of McCullgh-Victorville two lines
*  No SC bypass
*  CC cards for post-transient only
*
*   Fault bus at Victorville
FB   0.0 "VICTORVL" 287.
*
*
*   Clear fault at Victorville
CFB  4.0 "VICTORVL" 287.
*
*   Trip VICTORVL - CENTURY 287 lines
*
DL   4.0 "VICTORVL" 287. "CNTURY1 " 287. "1 "
DL   4.0 "VICTORVL" 287. "CNTURY2 " 287. "1 "
*
*  Readjust Northwest SVC's
CC  MSV  0.0 "KEEL-SVC" 230.0 "1 "  350. -300.
CC  MSV  0.0 "MV-SVC  " 230.0 "1 "  350. -300.
*   CC  MSV  0.0 "DALLES 3"  13.8 "1 "  180. -270.
*
*  Add SVC's at Marketplace and Adelanto
*
CC  MBS  120.0 "ADELSVC " 500. "sv" "A" 0.0 1.320
CC  MBS  120.0 "MKTPSVC " 500. "sv" "A" 0.0 1.320
```

Rinaldi - Tarzana 230 kV Lines 1 & 2 16

```
RUN
*   Loss of Rinaldi-Tarzana two lines
*   Fault bus at Rinaldi 230
FB   0.0 "RINALDI" 230.
*
*  Temporary block all DC
*
DDC   0.0 "INT MT1R"  206. "ADELAN1I" 202.
DDC   0.0 "CELILO1 "  500. "SYLMAR1 " 230.
DDC   0.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*   Clear fault at Adelanto
```

CFB 4.0 "RINALDI" 230.
*
* Restart all DC
*
SDC   4.0 "INT MT1R" 206. "ADELAN1I" 202.
SDC   4.0 "CELILO1 " 500. "SYLMAR1 " 230.
SDC   4.0 "CELILO2 " 500. "SYLMAR2 " 230.
*
*   Trip Rinaldi - Tarzana lines
*
DL   0.0 "RINALDI " 230. "TARZANA " 230. "1 "
DL   0.0 "RINALDI " 230. "TARZANA " 230. "2 "

Rinaldi-Glendale 230 kV Lines 1&2 17

RUN
*   Loss of Rinaldi-Glendale two lines
*   Fault bus at Rinaldi 230
FB   0.0 "RINALDI" 230.
*
* Temporary block all DC
*
DDC   0.0 "INT MT1R" 206. "ADELAN1I" 202.
DDC   0.0 "CELILO1 " 500. "SYLMAR1 " 230.
DDC   0.0 "CELILO2 " 500. "SYLMAR2 " 230.
*
*   Clear fault at Adelanto
CFB 4.0 "RINALDI" 230.
*
* Restart all DC
*
SDC   4.0 "INT MT1R" 206. "ADELAN1I" 202.
SDC   4.0 "CELILO1 " 500. "SYLMAR1 " 230.
SDC   4.0 "CELILO2 " 500. "SYLMAR2 " 230.
*
*   Trip Rinaldi - Tarzana lines
*
DL   0.0 "RINALDI " 230. "GLENDAL " 230. "1 "
DL   0.0 "RINALDI " 230. "GLENDAL " 230. "2 "
*

Rinaldi-Valley 230 kV Lines 1 & 2 18

RUN
*   Loss of Rinaldi-Valley two lines
*
*   Fault bus at Rinaldi 230
FB   0.0 "RINALDI " 230.
*
* Temporary block all DC
*
DDC   0.0 "INT MT1R" 206. "ADELAN1I" 202.
DDC   0.0 "CELILO1 " 500. "SYLMAR1 " 230.
DDC   0.0 "CELILO2 " 500. "SYLMAR2 " 230.
*

```
*   Clear fault at RINALDI
CFB  4.0 "RINALDI  " 230.
*
*  Restart all DC
*
SDC   4.0 "INT MT1R"  206. "ADELAN1I" 202.
SDC   4.0 "CELILO1 "  500. "SYLMAR1 " 230.
SDC   4.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*   Trip Rinaldi - Valley lines
*
DL   0.0 "RINALDI " 230. "VALLEY  " 230. "1 "
DL   0.0 "RINALDI " 230. "VALLEY  " 230. "2 "
```

Toluca-Valley 230 kV Lines 1&2 19

```
RUN
*   Loss of Valley-Toluca two lines
*
*   Fault bus at Toluca 230
FB   0.0 "TOLUCA  " 230.
*
*
*  Temporary block all DC
*
DDC   0.0 "INT MT1R"  206. "ADELAN1I" 202.
DDC   0.0 "CELILO1 "  500. "SYLMAR1 " 230.
DDC   0.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*
*   Clear fault at Toluca
CFB  4.0 "TOLUCA   " 230.
*
*  Restart all DC
*
SDC   4.0 "INT MT1R"  206. "ADELAN1I" 202.
SDC   4.0 "CELILO1 "  500. "SYLMAR1 " 230.
SDC   4.0 "CELILO2 "  500. "SYLMAR2 " 230.
*
*   Trip Rinaldi - Tarzana lines
*
DL   0.0 "TOLUCA  " 230. "VALLEY  " 230. "1 "
DL   0.0 "TOLUCA  " 230. "VALLEY  " 230. "2 "
*
```

Glendale-Atwater 230 kV Lines 1&2 20

```
RUN
*   Loss of Glendale-Atwater two lines
*
*   Fault bus at Glendale 230
FB   0.0 "GLENDAL " 230.
*
*   Clear fault at Glendale 230
CFB  4.0 "GLENDAL" 230.
```

*
* Trip Rinaldi - Tarzana lines
*
DL 0.0 "ATWATER " 230. "GLENDAL " 230. "1 "
DL 0.0 "ATWATER " 230. "GLENDAL " 230. "2 "
*

Tarzana-Olympic 230 kV and 138k V Lines 21

RUN
* Loss of Tarzana-Olympic two lines
*
* Fault bus at TARZANA 230
FB 0.0 "TARZANA" 230.
*
*
* Clear fault at TARZANA 230
CFB 4.0 "TARZANA" 230.
*
* Trip Tarzana-Olympic lines
*
DL 0.0 "TARZANA" 230. "OLYMPC " 230. "1 "
DL 0.0 "TARZANA" 138. "OLYMPLD " 138. "1 "
*

Velasco-Century 230kV Lines 1&2 22

RUN
* Loss of Velasco-Century two lines
*
* Fault bus at Velasco 230
FB 0.0 "VELASCO " 230.
*
* Clear fault at Glendale 230
CFB 4.0 "VELASCO " 230.
*
* Trip Rinaldi - Tarzana lines
*
DL 0.0 "VELASCO " 230. "CNTURYLD" 230. "1 "
DL 0.0 "VELASCO " 230. "CNTURYLD" 230. "2 "

Century - Wilmington 138kV Lines 1 & 2 23

RUN
* Loss of CNTURY - WILMINGTON two lines
*
* Fault bus at CNTURY 138
FB 0.0 "CNTURY " 138.
*
* Clear fault at Glendale 230
CFB 4.0 "CNTURY " 138.
*
* Trip Rinaldi - Tarzana lines
*
DL 0.0 "CNTURY " 138. "WILMNTN " 138. "1 "
DL 0.0 "CNTURY " 138. "WILMNTN " 138. "2 "
*

Gramercy-Fairfax 138kV Lines 1 &2 24

```
RUN
*   Loss of GRAMERCY - FAIRFAX two lines
*
*   Fault bus at GRAMERCY 138
FB   0.0 "GRAMERCY" 138.
*
*   Clear fault at GRAMERCY 230
CFB  4.0 "GRAMERCY" 138.
*
*   Trip Gramercy - Fairfax lines
*
DL   0.0 "GRAMERCY" 138. "FAIRFAX" 138. "1 "
DL   0.0 "GRAMERCY" 138. "FAIRFAX" 138. "2 "
*
```

Century-Gramercy 138kV Lines 1 &2 25

```
RUN
*   Loss of CNTURY - GRAMERCY two lines
*  CC cards for post-transient only
*
*   Fault bus at CNTURY 138
FB   0.0 "CNTURY  " 138.
*
*   Clear fault at CNTURY 230
CFB  4.0 "CNTURY  " 138.
*
*   Trip Century - Gramercy lines
*
DL   0.0 "CNTURY  " 138. "GRAMERCY" 138. "1 "
DL   0.0 "CNTURY  " 138. "GRAMERCY" 138. "2 "
*
```

Gramercy – Tap1 & Tap2 138 kV Lines 26

```
RUN
*   Loss of GRAMERCY - TAP two lines
*  CC cards for post-transient only
*
*   Fault bus at GRAMERCY 138
FB   0.0 "GRAMERCY" 138.
*
*   Clear fault at GRAMERCY 230
CFB  4.0 "GRAMERCY" 138.
*
*   Trip Gramercy – Tap lines
*
DL   0.0 "GRAMERCY" 138. "TAP1    " 138. "1 "
DL   0.0 "GRAMERCY" 138. "TAP2    " 138. "2 "
```

Airport – Fairfax 138 kV Lines 27

```
RUN
*   Loss of AIRPORT - FAIRFAX two lines
*   Fault bus at AIRPORT 138
*
FB   0.0 "AIRPORT" 138.
*
*
*   Clear fault at AIRPORT 230
CFB  4.0 "AIRPORT" 138.
*
*   Trip Airport - Fairfax lines
*
DL   0.0 "AIRPORT" 138. "FAIRFAX" 138. "1 "
DL   0.0 "AIRPORT" 138. "FAIRFAX" 138. "2 "
*
```

Barren Ridge–Haskell 230 kV Lines 1&2 28

```
RUN
*   Loss of BARRENRD-HASKELL two lines
*  CC cards for post-transient only
*
*   Fault bus at BARRENRD 230
FB   0.0 "BARRENRD" 230.
*
*   Clear fault at
CFB  4.0 "BARRENRD" 230.
*
*   Trip BARRENRD - HSKLLCYN lines
*
DL   4.0 "BARRENRD" 230. "HSKLLCYN" 230. "1 "
DL   4.0 "BARRENRD" 230. "KSKLLCYN" 230. "2 "
*
*
* Trip Pinetree Wind, Solar and Beacon
TG  8.0  "PTWTG   " 0.57  "**"
TG  8.0  "PCWTG   " 0.57  "**"
TG  8.0  "PTSOL   " 0.48  "**"
TG  8.0  "BEACONPV" 0.29  "**"
*
DL  8.0  "BEACONTP" 230. "BARRENRD" 230. "1 "
DL  8.0  "PT230   " 230. "BARRENRD" 230. "1 "
*
*   Trip OWENYO and ODLSR
*
TG  12.0  "OWENYO_S" 0.48  "**"
TG  12.0  "OLDSR   " 0.48  "**"
*
```

Toluca– Hollywood Lines 1, 2, and 3 29

```
RUN
*   Loss of Toluca - Holywood triple towers
*  CC cards for post-transient only
```

```
*
*
*   Trip Toluca - Holywood lines
*
DL   0.0 "TOLUCA  " 230. "HOLYWD_E" 230. "1 "
DL   0.0 "TOLUCA  " 230. "HOLYWD_F" 230. "3 "
DL   0.0 "TOLUCA  " 138. "HOLYWDLD" 230. "2 "
*
```

Rinaldi–Tarzana Lines 1 & 2 and Northridge-Tarzana Line 1 30

```
RUN
*   Loss of Northridge-Tarzana tripple tower
*  CC cards for post-transient only
*
*   Trip Rinaldi/Northridge - Tarzana lines
*
DL   0.0 "RINALDI " 230. "TARZANA " 230. "1 "
DL   0.0 "RINALDI " 230. "TARZANA " 230. "2 "
DL   0.0 "NRTHRDGE" 230. "TARZANA " 230. "1 "
*
```

Rinaldi–Tarzana Lines 1 & 2 and Northridge-Tarzana Line with load shed 31

```
RUN
*   Loss of Northridge-Tarzana tripple tower w/ load shed @ CAN
*  CC cards for post-transient only
*
*   Trip Rinaldi/Northridge - Tarzana lines
*
DL   0.0 "RINALDI " 230. "TARZANA " 230. "1 "
DL   0.0 "RINALDI " 230. "TARZANA " 230. "2 "
DL   0.0 "NRTHRDGE" 230. "TARZANA " 230. "1 "
*
*
*  Drop Canoga  Load
*
MBL  0.0 "CAN  A M "  34.5 "A" "D"
MBL  0.0 "CAN  B M "  34.5 "B" "D"
MBL  0.0 "CAN  C M "  34.5 "C" "D"
*
*  Add SVC's at Marketplace and Adelanto
*
CC  MBS  120.0 "ADELSVC " 500. "sv" "A" 0.0 1.320
CC  MBS  120.0 "MKTPSVC " 500. "sv" "A" 0.0 1.320
*
```

Appendix H. Power Flow Results

This page is intentionally left blank

2011 TEN-YEAR PLAN
CONTINGENCY ANALYSES RESULTS
HEAVY SUMMER

CONT. NO.	FROM	TO	CKT	IMPACTED ELEMENT	BASE CASE YEAR									
					hs12	hs13	hs14	hs15	hs16	hs17	hs18	hs19	hs20-hicasrtaic-ltc-hsk	hs21-hicasrtaic-ltc-hsk
(N-0) CONTINGENCY														
				BARRENRD - RINALDI 230kV Line 1			**100%**							
NERC CATEGORY B CONTINGENCY														
500kV Lines														
1	26003 ADELANTO	26115 RINALDI2	1	SCATERGD - OLYMPC 230kV Line 2	91%	91%								
2	26003 ADELANTO	26079 TOLUCA	1	VALLEY - TOLUCA 230kV Line 1 VALLEY - TOLUCA 230kV Line 2 VALLEY - RINALDI 230kV Line 1 VALLEY - RINALDI 230Kv Line 2							92% 92% 92% 92%	93% 93% 93% 93%		
3	26044 MARKETPL	26003 ADELANTO	1											
4	26044 MARKETPL	26048 MCCULLGH	1											
5	26048 MCCULLGH	26105 VICTORVL	1											
6	26105 VICTORVL	26003 ADELANTO	1											
7	26105 VICTORVL	24086 LUGO	1	SCATERGD - OLYMPC 230kV Line 2	91%	91%								
8	26105 VICTORVL	26062 RINALDI	1	SCATERGD - OLYMPC 230kV Line 2	91%	91%								
287kV Lines														
9	26051 MEAD	26104 VICTORVL	1											
10	26104 VICTORVL	26070 CNTURY1	1											
11	26104 VICTORVL	26071 CNTURY2	1											
230kV Lines														
12	26081 ATWATER	26068 STJOHN	1											
13	26081 ATWATER	26080 VELASCO	1											
14	26132 BARRENRD	26905 BCON230	1											
15	26132 BARRENRD	26136 COTTONWD	1											
16	26132 BARRENRD	26135 HSKLLCYN	2											
17	26132 BARRENRD	26135 HSKLLCYN	3											

2011 TEN-YEAR PLAN
CONTINGENCY ANALYSES RESULTS
HEAVY SUMMER

CONT. NO.	FROM	TO	CKT	IMPACTED ELEMENT	BASE CASE YEAR									
					hs12	hs13	hs14	hs15	hs16	hs17	hs18	hs19	hs20-hicasrtaic-ltc-hsk	hs21-hicasrtaic-ltc-hsk
18	26132 BARRENRD	26061 RINALDI	1											
19	26010 CASTAIC	26035 HSKLLCYN	1											
20	26010 CASTAIC	26086 NRTHRDGE	1											
21	26010 CASTAIC	26052 OLIVE	1											
22	26010 CASTAIC	26094 SYLMARLA	1											
23	26013 GLENDAL	26081 ATWATER	1											
24	26025 HAYNES	26081 ATWATER	1											
25	26025 HAYNES	26063 RIVER	1	HAYNES - VELASCO 230kV Line 1									90%	91%
26	26025 HAYNES	26068 STJOHN	1											
27	26025 HAYNES	26080 VELASCO	1											
28	27031 PT230	26132 BARRENRD	1											
29	26135 HSKLLCYN	26052 OLIVE	1											
30	26086 NRTHRDGE	26093 TARZANA	1	SCATERGD - OLYMPC 230kV Line 2	91%	91%								
31	26052 OLIVE	26086 NRTHRDGE	1											
32	26061 RINALDI	26013 GLENDAL	1											
33	26061 RINALDI	26135 HSKLLCYN	1											
34	26061 RINALDI	26093 TARZANA	1	SCATERGD - OLYMPC 230kV Line 2	95%	95%	93%							
				RINALDI - TARZANA 230kV Line 2			93%							
35	26066 SCATERGD	26087 OLYMPC	2	SCATERGD - AIRPORT 138kV Line 1	96%	96%	96%							
				SCATERGD - AIRPORT 138kV Line 2	96%	96%	96%							
36	26066 SCATERGD	26087 OLYMPC	1											
37	26068 STJOHN	26063 RIVER	1											
38	26094 SYLMARLA	26135 HSKLLCYN	1											
39	26094 SYLMARLA	26086 NRTHRDGE	1	SCATERGD - OLYMPC 230kV Line 2	94%	94%	92%							
40	26094 SYLMARLA	26061 RINALDI	1											
41	26093 TARZANA	26087 OLYMPC	3	SCATERGD - OLYMPC 230kV Line 2	99%	99%	98%							

2011 TEN-YEAR PLAN
CONTINGENCY ANALYSES RESULTS
HEAVY SUMMER

CONT. NO.	FROM	TO	CKT	IMPACTED ELEMENT	BASE CASE YEAR									
					hs12	hs13	hs14	hs15	hs16	hs17	hs18	hs19	hs20-hicasrtaic-ltc-hsk	hs21-hicasrtaic-ltc-hsk
42	26078 TOLUCA	26081 ATWATER	1											
43	26078 TOLUCA	26082 HOLYWD_E	1											
44	26078 TOLUCA	26182 HOLYWD_F	1											
45	26103 VALLEY	26061 RINALDI	1											
46	26103 VALLEY	26078 TOLUCA	1	VALLEY - TOLUCA 230kV Line 2									96%	99%
47	26080 VELASCO	26072 CNTURYLD	1											
48	24729 INYO	26136 COTTONWD	1											
49	26946 OWENYOTP	26136 COTTONWD	1											
50	26946 OWENYOTP	24729 INYO	1											
51	26946 OWENYOTP	26998 ODLSR	1											
52	26998 ODLSR	26136 COTTONWD	1											
138kV Lines														
53	26069 CNTURY	26014 GRAMERC1	1											
54	26069 CNTURY	26014 GRAMERCY	1											
55	26069 CNTURY	26073 WLMNTN	1											
56	26076 FAIRFAX	26089 AIRPORT	1	`										
57	26076 FAIRFAX	26014 GRAMERC1	1											
58	26076 FAIRFAX	26014 GRAMERCY	1											
59	26076 FAIRFAX	26088 OLYMPCLD	1											
60	26091 HARBOR	26073 WLMNTN	E											
61	26019 HARB	26075 WLMNTNLD	A											
62	26083 HOLYWD1	26076 FAIRFAX	1											
63	26083 HOLYWD1	26085 HOLYWDLD	1											
64	26065 SCATERGD	26089 AIRPORT	1	SCATERGD - OLYMPC 230kV Line 2	94%	94%	91%							
65	26095 TAP1	26016 HALLDALE	1											
66	26096 TAP2	26016 HALLDALE	1											

2011 TEN-YEAR PLAN
CONTINGENCY ANALYSES RESULTS
HEAVY SUMMER

CONT. NO.	FROM	TO	CKT	IMPACTED ELEMENT	BASE CASE YEAR									
					hs12	hs13	hs14	hs15	hs16	hs17	hs18	hs19	hs20-hicasrtaic-ltc-hsk	hs21-hicasrtaic-ltc-hsk
67	26095 TAP1	26014 GRAMERC1	1											
68	26096 TAP2	26015 GRAMERC2	1											
69	26095 TAP1	26014 GRAMERCY	1											
70	26096 TAP2	26014 GRAMERCY	1											
71	26092 TARZANA	26088 OLYMPCLD	1											
72	26077 TOLUCA	26085 HOLYWDLD	2											
73	26073 WLMNTN	26095 TAP1	1											
74	26073 WLMNTN	26096 TAP2	1											
75	26075 WLMNTNLD	26073 WLMNTN	1											
76	26075 WLMNTNLD	26019 HARB	A											
Auto-Transformers														
77	26070 CNTURY1	26069 CNTURY	G											
78	26071 CNTURY2	26069 CNTURY	F											
79	26072 CNTURYLD	26069 CNTURY	E											
80	26087 OLYMPC	26088 OLYMPCLD	E	OLYMPC - OLYMPCLD 230/138kV xfmr "F"				91%	92%	94%	95%	96%		91%
81	26066 SCATERGD	26065 SCATERGD	1	SCATERGD - OLYMPC 230kV Line 2	**110%**	**110%**	**110%**							
82	26105 VICTORVL	26104 VICTORVL	1											
NERC CATEGORY C5 CONTINGENCY														
500kV Lines														
1	26003 ADELANTO	26115 RINALDI2	1	SCATERGD - OLYMPC 230kV Line 2	97%	97%	95%							
	26105 VICTORVL	26062 RINALDI	1											
2	26048 MCCULLGH	26105 VICTORVL	1											
	26048 MCCULLGH	26105 VICTORVL	2											
3	26105 VICTORVL	26003 ADELANTO	1											
	26105 VICTORVL	26003 ADELANTO	2											

2011 TEN-YEAR PLAN
CONTINGENCY ANALYSES RESULTS
HEAVY SUMMER

CONT. NO.	FROM	TO	CKT	IMPACTED ELEMENT	BASE CASE YEAR									
					hs12	hs13	hs14	hs15	hs16	hs17	hs18	hs19	hs20-hicasrtaic-ltc-hsk	hs21-hicasrtaic-ltc-hsk
4				VALLEY - TOLUCA 230kV Line 1							93%	94%		
	26003 ADELANTO	26079 TOLUCA	1	VALLEY - TOLUCA 230kV Line 2							93%	94%		
	26003 ADELANTO	26044 MARKETPL	1	VALLEY - RINALDI 230kV Line 1							92%	94%		
				VALLEY - RINALDI 230kV Line 2							92%	94%		
5	26003 ADELANTO	26105 VICTORVL	2	SCATERGD - OLYMPC 230kV Line 2	91%	91%								
	26003 ADELANTO	26115 RINALDI2	1											
6	26105 VICTORVL	26003 ADELANTO	1	SCATERGD - OLYMPC 230kV Line 2	91%	91%								
	26105 VICTORVL	24086 LUGO	1											
7	26003 ADELANTO	26105 VICTORVL	2											
	26048 MCCULLGH	26105 VICTORVL	2											
8	26048 MCCULLGH	26105 VICTORVL	1											
	26048 MCCULLGH	24042 ELDORDO	1											
345kV Lines														
9	27135 MWC345	26043 INTERMT	1											
	26043 INTERMT	65995 MONA	1											
287kV Lines														
10	26104 VICTORVL	26070 CNTURY1	1											
	26104 VICTORVL	26071 CNTURY2	1											
230kV Lines														
11	26010 CASTAIC	26135 HSKLLCYN	1											
	26010 CASTAIC	26135 HSKLLCYN	2											
12	26135 HSKLLCYN	26094 SYLMARLA	1											
	26135 HSKLLCYN	26010 CASTAIC	1											
13	26135 HSKLLCYN	26052 OLIVE	1											
	26010 CASTAIC	26135 HSKLLCYN	2											

2011 TEN-YEAR PLAN
CONTINGENCY ANALYSES RESULTS
HEAVY SUMMER

CONT. NO.	FROM	TO	CKT	IMPACTED ELEMENT	BASE CASE YEAR									
					hs12	hs13	hs14	hs15	hs16	hs17	hs18	hs19	hs20-hicasrtaic-ltc-hsk	hs21-hicasrtaic-ltc-hsk
14	26135 HSKLLCYN	26061 RINALDI	1											
	26010 CASTAIC	26135 HSKLLCYN	3											
15	26013 GLENDAL	26081 ATWATER	1											
	26013 GLENDAL	26061 RINALDI	2											
16	26013 GLENDAL	26081 ATWATER	2											
	26013 GLENDAL	26061 RINALDI	1											
17	26103 VALLEY	26061 RINALDI	2											
	26103 VALLEY	26078 TOLUCA	2											
18	26132 BARRENRD	26061 RINALDI	1											
	26103 VALLEY	26061 RINALDI	1											
19	26094 SYLMARLA	26061 RINALDI	3	SCATERGD - OLYMPC 230kV Line 2	95%	94%	92%							
	26061 RINALDI	26093 TARZANA	1	RINALDI - TARZANA 230kV Line 2			91%							
20	26093 TARZANA	26086 NRTHRDGE	1	SCATERGD - OLYMPC 230kV Line 2	100%	100%	100%							
	26093 TARZANA	26087 OLYMPC	3											
21	26013 GLENDAL	26081 ATWATER	1											
	26013 GLENDAL	26081 ATWATER	2											
22	26061 RINALDI	26113 GLENDAL	1											
	26061 RINALDI	26113 GLENDAL	2											
23	26061 RINALDI	26093 TARZANA	1	SYLMARLA - NRTHRDGE 230kV Line 1	96%	96%	100%							
	26061 RINALDI	26093 TARZANA	2	SCATERGD - OLYMPC 230kV Line 2	**116%**	**116%**	**116%**							
				NRTHRDGE - TARZANA 230kV Line 1					90%	91%	95%	97%	97%	**100.7%**
24	26093 TARZANA	26087 OLYMPC	3	SCATERGD - OLYMPC 230kV Line 2	**128%**	**128%**	**130%**							
	26092 TARZANA	26088 OLYMPCLD	1											
25	26103 VALLEY	26061 RINALDI	1											
	26103 VALLEY	26061 RINALDI	2											

2011 TEN-YEAR PLAN
CONTINGENCY ANALYSES RESULTS
HEAVY SUMMER

CONT. NO.	FROM	TO	CKT	IMPACTED ELEMENT	BASE CASE YEAR									
					hs12	hs13	hs14	hs15	hs16	hs17	hs18	hs19	hs20-hicasrtaic-ltc-hsk	hs21-hicasrtaic-ltc-hsk
26	26103 VALLEY	26078 TOLUCA	1											
	26103 VALLEY	26078 TOLUCA	2											
27	26080 VELASCO	26072 CNTURYLD	1											
	26080 VELASCO	26072 CNTURYLD	2											
28	26068 STJOHN	26063 RIVER	1											
	26063 RIVER	26631 MKT A HI	A											
29	26025 HAYNES	26080 VELASCO	1	HAYNES - VELASCO 230kV Line 1									90%	91%
	26063 RIVER	26632 MKT B HI	B											
30	26063 RIVER	26080 VELASCO	1											
	26063 RIVER	26633 MKT C HI	C											
138kV Lines														
31	26065 SCATERGD	26089 AIRPORT	2	SCATERGD - OLYMPC 230kV Line 2	94%	94%	91%							
	26089 AIRPORT	26076 FAIRFAX	2											
32	26065 SCATERGD	26089 AIRPORT	1	SCATERGD - OLYMPC 230kV Line 2	94%	94%	91%							
	26089 AIRPORT	26076 FAIRFAX	1											
33	26069 CNTURY	26014 GRAMERC1	1											
	26069 CNTURY	26015 GRAMERC2	1											
34	26069 CNTURY	26014 GRAMERCY	1											
	26069 CNTURY	26014 GRAMERCY	2											
35	26069 CNTURY	26073 WLMNTN	1											
	26069 CNTURY	26073 WLMNTN	2											
36	26019 HARB	26075 WLMNTNLD	A											
	26019 HARB	26075 WLMNTNLD	B											
37	26073 WLMNTN	26091 HARBOR	D	SCATERGD - OLYMPC 230kV Line 2	92%	92%								
	26073 WLMNTN	26091 HARBOR	E											

2011 TEN-YEAR PLAN
CONTINGENCY ANALYSES RESULTS
HEAVY SUMMER

CONT. NO.	FROM	TO	CKT	IMPACTED ELEMENT	BASE CASE YEAR									
					hs12	hs13	hs14	hs15	hs16	hs17	hs18	hs19	hs20-hicasrtaic-ltc-hsk	hs21-hicasrtaic-ltc-hsk
38	26076 FAIRFAX 26076 FAIRFAX	26089 AIRPORT 26089 AIRPORT	1 2	SCATERGD - OLYMPC 230kV Line 2	93%	93%	92%							
39	26076 FAIRFAX 26076 FAIRFAX	26014 GRAMERC1 26015 GRAMERC2	1 1											
40	26076 FAIRFAX 26076 FAIRFAX	26014 GRAMERCY 26014 GRAMERCY	1 2											
41	26076 FAIRFAX 26076 FAIRFAX	26083 HOLYWD1 26084 HOLYWD2	1 1											
42	26095 TAP 1 26096 TAP 2	26014 GRAMERC1 26015 GRAMERC2	1 1											
43	26095 TAP 1 26096 TAP 2	26014 GRAMERCY 26014 GRAMERCY	1 1											
44	26073 WLMNTN 26073 WLMNTN	26095 TAP 1 26096 TAP 2	1 1											
45	26091 HARBOR 26091 HARBOR	26095 TAP 1 26096 TAP 2	1 1											
46	26016 HALLDALE 26016 HALLDALE	26095 TAP 1 26096 TAP 2	1 1											
NERC CATEGORY C2 CONTINGENCY														
500kV Lines														
1	26003 ADELANTO 26105 VICTORVL	26115 RINALDI2 26003 ADELANTO	1 2	SCATERGD- OLYMPC 230kV Line 2	91%	91%								
2	26003 ADELANTO 26044 MARKETPL	26079 TOLUCA 26003 ADELANTO	1 1	VALLEY - TOLUCA 230kV Line 1 VALLEY - TOLUCA 230kV Line 2 VALLEY - RINALDI 230kV Line 1 VALLEY -RINALDI 230kV Line 2							93% 93% 92% 92%	94% 94% 94% 94%		

2011 TEN-YEAR PLAN
CONTINGENCY ANALYSES RESULTS
HEAVY SUMMER

CONT. NO.	FROM	TO	CKT	IMPACTED ELEMENT	BASE CASE YEAR									
					hs12	hs13	hs14	hs15	hs16	hs17	hs18	hs19	hs20-hicasrtaic-ltc-hsk	hs21-hicasrtaic-ltc-hsk
3	26105 VICTORVL	26003 ADELANTO	1	SCATERGD- OLYMPC 230kV Line 2	91%	91%								
	24086 LUGO	26105 VICTORVL	1											
4	26105 VICTORVL	26003 ADELANTO	2											
	26048 MCCULLGH	26105 VICTORVL	2											
5	26048 MCCULLGH	26105 VICTORVL	1											
	24042 ELDORDO	26048 MCCULLGH	1											
6	14003 NAVAJO	26123 CRYSTAL	1											
	26123 CRYSTAL	26048 MCCULLGH	1											
345kV Lines														
7	27135 MWC345	26043 INTERMT	1											
	26043 INTERMT	65995 MONA	1											
230kV Lines														
8	26010 SYLMARLA	26135 HSKLLCYN	1											
	26010 CASTAIC	26135 HSKLLCYN	1											
9	26135 HSKLLCYN	26052 OLIVE	1											
	26010 CASTAIC	26135 HSKLLCYN	2											
10	26135 HSKLLCYN	26061 RINALDI	1											
	26010 CASTAIC	26135 HSKLLCYN	3											
11	26081 ATWATER	26013 GLENDAL	1											
	26061 RINALDI	26013 GLENDAL	2											
12	26081 ATWATER	26013 GLENDAL	2											
	26061 RINALDI	26013 GLENDAL	1											
13	26103 VALLEY	26061 RINALDI	2											
	26103 VALLEY	26078 TOLUCA	2											
14	26094 SYLMARLA	26061 RINALDI	3											
	26010 CASTAIC	26094 SYLMARLA	1											

2011 TEN-YEAR PLAN
CONTINGENCY ANALYSES RESULTS
HEAVY SUMMER

CONT. NO.	FROM		TO		CKT	IMPACTED ELEMENT	BASE CASE YEAR									
							hs12	hs13	hs14	hs15	hs16	hs17	hs18	hs19	hs20-hicasrtaic-ltc-hsk	hs21-hicasrtaic-ltc-hsk
15	26094	SYLMARLA	26061	RINALDI	3	SCATERGD- OLYMPC 230kV Line 2	95%	94%	92%							
	26061	RINALDI	26093	TARZANA	1	RINALDI - TARZANA 230kV Line 2			91%							
16	26086	NRTHRDGE	26093	TARZANA	1	SCATERGD- OLYMPC 230kV Line 2	100%	100%	100%							
	26093	TARZANA	26087	OLYMPIC	3											
17	26068	STJOHN	26063	RIVER	1											
	26063	RIVER	26631	MKT "A"	A											
18	26025	HAYNES	26063	RIVER	1	HAYNES - VELASCO 230kV Line 1									90%	91%
	26063	RIVER	26632	MKT "B"	B											
19	26063	RIVER	26080	VELASCO	1											
	26063	RIVER	26633	MKT "C"	C											
20	26132	BARRENRD	26061	RINALDI	1											
	24729	INYO	26132	BARRENRD	1											
21	26132	BARRENRD	26061	RINALDI	1											
	26103	VALLEY	26061	RINALDI	1											
22	26065	SCATERGD	26089	AIRPORT	2	SCATERGD- OLYMPC 230kV Line 2	94%	94%	91%							
	26089	AIRPORT	26076	FAIRFAX	2											
23	26065	SCATERGD	26089	AIRPORT	1	SCATERGD- OLYMPC 230kV Line 2	94%	94%	91%							
	26089	AIRPORT	26076	FAIRFAX	1											

2011 TEN-YEAR PLAN
CONTINGENCY ANALYSES RESULTS
LIGHT WINTER

CONT. NO.	FROM		TO		CKT	IMPACTED ELEMENT	BASE CASE YEAR	
							lw12-lml	lw16-lml
(N-0) CONTINGENCY								
NERC CATEGORY B CONTINGENCY								
500kV Lines								
1	26003	ADELANTO	26115	RINALDI2	1			
2	26003	ADELANTO	26079	TOLUCA	1			
3	26044	MARKETPL	26003	ADELANTO	1			
4	26044	MARKETPL	26048	MCCULLGH	1			
5	26048	MCCULLGH	26105	VICTORVL	1			
6	26105	VICTORVL	26003	ADELANTO	1			
7	26105	VICTORVL	24086	LUGO	1			
8	26105	VICTORVL	26062	RINALDI	1			
287kV Lines								
9	26051	MEAD	26104	VICTORVL	1			
10	26104	VICTORVL	26070	CNTURY1	1			
11	26104	VICTORVL	26071	CNTURY2	1			
230kV Lines								
12	26081	ATWATER	26068	STJOHN	1			
13	26081	ATWATER	26080	VELASCO	1			
14	26132	BARRENRD	26905	BCON230	1			
15	26132	BARRENRD	26136	COTTONWD	1			
16	26132	BARRENRD	26135	HSKLLCYN	2			
17	26132	BARRENRD	26135	HSKLLCYN	3			
18	26132	BARRENRD	26061	RINALDI	1			
19	26010	CASTAIC	26035	HSKLLCYN	1			
20	26010	CASTAIC	26086	NRTHRDGE	1			
21	26010	CASTAIC	26052	OLIVE	1			
22	26010	CASTAIC	26094	SYLMARLA	1			
23	26013	GLENDAL	26081	ATWATER	1			
24	26025	HAYNES	26081	ATWATER	1			
25	26025	HAYNES	26063	RIVER	1			
26	26025	HAYNES	26068	STJOHN	1			
27	26025	HAYNES	26080	VELASCO	1			
28	27031	PT230	26132	BARRENRD	1			
29	26135	HSKLLCYN	26052	OLIVE	1			
30	26086	NRTHRDGE	26093	TARZANA	1			
31	26052	OLIVE	26086	NRTHRDGE	1			
32	26061	RINALDI	26013	GLENDAL	1			
33	26061	RINALDI	26135	HSKLLCYN	1			
34	26061	RINALDI	26093	TARZANA	1			
35	26066	SCATERGD	26087	OLYMPC	2			
36	26066	SCATERGD	26087	OLYMPC	1			

2011 TEN-YEAR PLAN
CONTINGENCY ANALYSES RESULTS
LIGHT WINTER

CONT. NO.	FROM		TO		CKT	IMPACTED ELEMENT	BASE CASE YEAR	
							lw12-lml	lw16-lml
37	26068	STJOHN	26063	RIVER	1			
38	26094	SYLMARLA	26135	HSKLLCYN	1			
39	26094	SYLMARLA	26086	NRTHRDGE	1			
40	26094	SYLMARLA	26061	RINALDI	1			
41	26093	TARZANA	26087	OLYMPC	3			
42	26078	TOLUCA	26081	ATWATER	1			
43	26078	TOLUCA	26082	HOLYWD_E	1			
44	26078	TOLUCA	26182	HOLYWD_F	1			
45	26103	VALLEY	26061	RINALDI	1			
46	26103	VALLEY	26078	TOLUCA	1			
47	26080	VELASCO	26072	CNTURYLD	1			
48	24729	INYO	26136	COTTONWD	1			
49	26946	OWENYOTP	26136	COTTONWD	1			
50	26946	OWENYOTP	24729	INYO	1			
51	26946	OWENYOTP	26998	ODLSR	1			
52	26998	ODLSR	26136	COTTONWD	1			
138kV Lines								
53	26069	CNTURY	26014	GRAMERC1	1			
54	26069	CNTURY	26014	GRAMERCY	1			
55	26069	CNTURY	26073	WLMNTN	1			
56	26076	FAIRFAX	26089	AIRPORT	1	`		
57	26076	FAIRFAX	26014	GRAMERC1	1			
58	26076	FAIRFAX	26014	GRAMERCY	1			
59	26076	FAIRFAX	26088	OLYMPCLD	1			
60	26091	HARBOR	26073	WLMNTN	E			
61	26019	HARB	26075	WLMNTNLD	A			
62	26083	HOLYWD1	26076	FAIRFAX	1			
63	26083	HOLYWD1	26085	HOLYWDLD	1			
64	26065	SCATERGD	26089	AIRPORT	1			
65	26095	TAP1	26016	HALLDALE	1			
66	26096	TAP2	26016	HALLDALE	1			
67	26095	TAP1	26014	GRAMERC1	1			
68	26096	TAP2	26015	GRAMERC2	1			
69	26095	TAP1	26014	GRAMERCY	1			
70	26096	TAP2	26014	GRAMERCY	1			
71	26092	TARZANA	26088	OLYMPCLD	1			
72	26077	TOLUCA	26085	HOLYWDLD	2			
73	26073	WLMNTN	26095	TAP1	1			
74	26073	WLMNTN	26096	TAP2	1			
75	26075	WLMNTNLD	26073	WLMNTN	1			
76	26075	WLMNTNLD	26019	HARB	A			

2011 TEN-YEAR PLAN
CONTINGENCY ANALYSES RESULTS
LIGHT WINTER

CONT. NO.	FROM		TO		CKT	IMPACTED ELEMENT	BASE CASE YEAR	
							lw12-lml	lw16-lml
Auto-Transformers								
77	26070	CNTURY1	26069	CNTURY	G			
78	26071	CNTURY2	26069	CNTURY	F			
79	26072	CNTURYLD	26069	CNTURY	E			
80	26087	OLYMPC	26088	OLYMPCLD	E			
81	26066	SCATERGD	26065	SCATERGD	1			
82	26105	VICTORVL	26104	VICTORVL	1			
NERC CATEGORY C5 CONTINGENCY								
500kV Lines								
1	26003	ADELANTO	26115	RINALDI2	1			
	26105	VICTORVL	26062	RINALDI	1			
2	26048	MCCULLGH	26105	VICTORVL	1			
	26048	MCCULLGH	26105	VICTORVL	2			
3	26105	VICTORVL	26003	ADELANTO	1			
	26105	VICTORVL	26003	ADELANTO	2			
4	26003	ADELANTO	26079	TOLUCA	1			
	26003	ADELANTO	26044	MARKETPL	1			
5	26003	ADELANTO	26105	VICTORVL	2			
	26003	ADELANTO	26115	RINALDI2	1			
6	26105	VICTORVL	26003	ADELANTO	1			
	26105	VICTORVL	24086	LUGO	1			
7	26003	ADELANTO	26105	VICTORVL	2			
	26048	MCCULLGH	26105	VICTORVL	2			
8	26048	MCCULLGH	26105	VICTORVL	1			
	26048	MCCULLGH	24042	ELDORDO	1			
345kV Lines								
9	27135	MWC345	26043	INTERMT	1			
	26043	INTERMT	65995	MONA	1			
287kV Lines								
10	26104	VICTORVL	26070	CNTURY1	1			
	26104	VICTORVL	26071	CNTURY2	1			
230kV Lines								
11	26010	CASTAIC	26135	HSKLLCYN	1			
	26010	CASTAIC	26135	HSKLLCYN	2			
12	26135	HSKLLCYN	26094	SYLMARLA	1			
	26135	HSKLLCYN	26010	CASTAIC	1			
13	26135	HSKLLCYN	26052	OLIVE	1			
	26010	CASTAIC	26135	HSKLLCYN	2			
14	26135	HSKLLCYN	26061	RINALDI	1			
	26010	CASTAIC	26135	HSKLLCYN	3			
15	26013	GLENDAL	26081	ATWATER	1			
	26013	GLENDAL	26061	RINALDI	2			

2011 TEN-YEAR PLAN
CONTINGENCY ANALYSES RESULTS
LIGHT WINTER

CONT. NO.	FROM		TO		CKT	IMPACTED ELEMENT	BASE CASE YEAR	
							lw12-lml	lw16-lml
16	26013	GLENDAL	26081	ATWATER	2			
	26013	GLENDAL	26061	RINALDI	1			
17	26103	VALLEY	26061	RINALDI	2			
	26103	VALLEY	26078	TOLUCA	2			
18	26132	BARRENRD	26061	RINALDI	1			
	26103	VALLEY	26061	RINALDI	1			
19	26094	SYLMARLA	26061	RINALDI	3			
	26061	RINALDI	26093	TARZANA	1			
20	26093	TARZANA	26086	NRTHRDGE	1			
	26093	TARZANA	26087	OLYMPC	3			
21	26013	GLENDAL	26081	ATWATER	1			
	26013	GLENDAL	26081	ATWATER	2			
22	26061	RINALDI	26113	GLENDAL	1			
	26061	RINALDI	26113	GLENDAL	2			
23	26061	RINALDI	26093	TARZANA	1			
	26061	RINALDI	26093	TARZANA	2			
24	26093	TARZANA	26087	OLYMPC	3			
	26092	TARZANA	26088	OLYMPCLD	1			
25	26103	VALLEY	26061	RINALDI	1			
	26103	VALLEY	26061	RINALDI	2			
26	26103	VALLEY	26078	TOLUCA	1			
	26103	VALLEY	26078	TOLUCA	2			
27	26080	VELASCO	26072	CNTURYLD	1			
	26080	VELASCO	26072	CNTURYLD	2			
28	26068	STJOHN	26063	RIVER	1			
	26063	RIVER	26631	MKT A HI	A			
29	26025	HAYNES	26080	VELASCO	1			
	26063	RIVER	26632	MKT B HI	B			
30	26063	RIVER	26080	VELASCO	1			
	26063	RIVER	26633	MKT C HI	C			
138kV Lines								
31	26065	SCATERGD	26089	AIRPORT	2			
	26089	AIRPORT	26076	FAIRFAX	2			
32	26065	SCATERGD	26089	AIRPORT	1			
	26089	AIRPORT	26076	FAIRFAX	1			
33	26069	CNTURY	26014	GRAMERC1	1			
	26069	CNTURY	26015	GRAMERC2	1			
34	26069	CNTURY	26014	GRAMERCY	1			
	26069	CNTURY	26014	GRAMERCY	2			
35	26069	CNTURY	26073	WLMNTN	1			
	26069	CNTURY	26073	WLMNTN	2			

2011 TEN-YEAR PLAN
CONTINGENCY ANALYSES RESULTS
LIGHT WINTER

CONT. NO.	FROM		TO		CKT	IMPACTED ELEMENT	BASE CASE YEAR	
							lw12-lml	lw16-lml
36	26019	HARB	26075	WLMNTNLD	A			
	26019	HARB	26075	WLMNTNLD	B			
37	26073	WLMNTN	26091	HARBOR	D			
	26073	WLMNTN	26091	HARBOR	E			
38	26076	FAIRFAX	26089	AIRPORT	1			
	26076	FAIRFAX	26089	AIRPORT	2			
39	26076	FAIRFAX	26014	GRAMERC1	1			
	26076	FAIRFAX	26015	GRAMERC2	1			
40	26076	FAIRFAX	26014	GRAMERCY	1			
	26076	FAIRFAX	26014	GRAMERCY	2			
41	26076	FAIRFAX	26083	HOLYWD1	1			
	26076	FAIRFAX	26084	HOLYWD2	1			
42	26095	TAP 1	26014	GRAMERC1	1			
	26096	TAP 2	26015	GRAMERC2	1			
43	26095	TAP 1	26014	GRAMERCY	1			
	26096	TAP 2	26014	GRAMERCY	1			
44	26073	WLMNTN	26095	TAP 1	1			
	26073	WLMNTN	26096	TAP 2	1			
45	26091	HARBOR	26095	TAP 1	1			
	26091	HARBOR	26096	TAP 2	1			
46	26016	HALLDALE	26095	TAP 1	1			
	26016	HALLDALE	26096	TAP 2	1			
NERC CATEGORY C2 CONTINGENCY								
500kV Lines								
1	26003	ADELANTO	26115	RINALDI2	1			
	26105	VICTORVL	26003	ADELANTO	2			
2	26003	ADELANTO	26079	TOLUCA	1			
	26044	MARKETPL	26003	ADELANTO	1			
3	26105	VICTORVL	26003	ADELANTO	1			
	24086	LUGO	26105	VICTORVL	1			
4	26105	VICTORVL	26003	ADELANTO	2			
	26048	MCCULLGH	26105	VICTORVL	2			
5	26048	MCCULLGH	26105	VICTORVL	1			
	24042	ELDORDO	26048	MCCULLGH	1			
6	14003	NAVAJO	26123	CRYSTAL	1			
	26123	CRYSTAL	26048	MCCULLGH	1			
345kV Lines								
7	27135	MWC345	26043	INTERMT	1			
	26043	INTERMT	65995	MONA	1			
230kV Lines								
8	26010	SYLMARLA	26135	HSKLLCYN	1			
	26010	CASTAIC	26135	HSKLLCYN	1			

2011 TEN-YEAR PLAN
CONTINGENCY ANALYSES RESULTS
LIGHT WINTER

CONT. NO.	FROM		TO		CKT	IMPACTED ELEMENT	BASE CASE YEAR	
							lw12-lml	lw16-lml
9	26135	HSKLLCYN	26052	OLIVE	1			
	26010	CASTAIC	26135	HSKLLCYN	2			
10	26135	HSKLLCYN	26061	RINALDI	1			
	26010	CASTAIC	26135	HSKLLCYN	3			
11	26081	ATWATER	26013	GLENDAL	1			
	26061	RINALDI	26013	GLENDAL	2			
12	26081	ATWATER	26013	GLENDAL	2			
	26061	RINALDI	26013	GLENDAL	1			
13	26103	VALLEY	26061	RINALDI	2			
	26103	VALLEY	26078	TOLUCA	2			
14	26094	SYLMARLA	26061	RINALDI	3			
	26010	CASTAIC	26094	SYLMARLA	1			
15	26094	SYLMARLA	26061	RINALDI	3			
	26061	RINALDI	26093	TARZANA	1			
16	26086	NRTHRDGE	26093	TARZANA	1			
	26093	TARZANA	26087	OLYMPIC	3			
17	26068	STJOHN	26063	RIVER	1			
	26063	RIVER	26631	MKT "A"	A			
18	26025	HAYNES	26063	RIVER	1			
	26063	RIVER	26632	MKT "B"	B			
19	26063	RIVER	26080	VELASCO	1			
	26063	RIVER	26633	MKT "C"	C			
20	26132	BARRENRD	26061	RINALDI	1			
	24729	INYO	26132	BARRENRD	1			
21	26132	BARRENRD	26061	RINALDI	1			
	26103	VALLEY	26061	RINALDI	1			
22	26065	SCATERGD	26089	AIRPORT	2			
	26089	AIRPORT	26076	FAIRFAX	2			
23	26065	SCATERGD	26089	AIRPORT	1			
	26089	AIRPORT	26076	FAIRFAX	1			

Appendix I. Transient and Post-Transient Stability Results

This page is intentionally left blank

2011 Ten Year Plan

Transient & Post Transient Results

2012 Heavy Summer

CONT. NO.	OUTAGE	STABLE	Possible Violations			Post-Transient	
			MORC1	MORC2	FREQ DIP	ΔV>5%	ΔV>10%
(N-1) CONTINGENCY							
1	Adelanto-Rinaldi 500kV line	Yes	None	None	None	None	
2	Adelanto-Toluca 500kV line	Yes	None	None	None	None	
3	Adelanto-Victorville 500kV line	Yes	None	None	None	None	
4	Lugo-Victorville 500kV Line	Yes	None	None	None	None	
5	Victorville-Rinaldi 500kV Line	Yes	None	None	None	None	
6	Mccullgh-Victorville 500kV Line	Yes	None	None	None	None	
7	Mead-Victorville 287 kV Line	Yes	None	None	None	None	
8	Cottonwd-Barren Ridge 230 kV with Remedial Action Scheme (RAS)	Yes	None	None	None	None	
9	Rinaldi-Barren Ridge 230 kV Line	Yes	None	None	None	None	
10	PDCI bipole	Yes	None	None	None	None	
(N-2) CONTINGENCY							
11	IPP DC Bipole	Yes	None	None	None		None
12	Palo Verde-g2-OL-MA-RAS	Yes	None	None	None		None
13	Adelanto-Rinaldi and Victorville-Rinaldi 500 kV Lines	Yes	None	None	None		None
14	McCullgh-Victorville 500 kV Lines 1 & 2	Yes	None	None	None		None
15	Victorville-Century 287 kV Lines 1 & 2						
16	Rinaldi-Tarzana 230 kV Lines 1 & 2	Yes	None	None	None		None
17	Rinaldi-Glendale 230 kV Lines 1 & 2	Yes	None	None	None		None
18	Rinaldi-Valley 230 kV Lines 1 & 2	Yes	None	None	None		None
19	Toluca- Valley 230 kV Lines 1 & 2	Yes	None	None	None		None
20	Glendale-Atwater 230 kV Lines 1 & 2	Yes	None	None	None		None
21	Tarzana-Olympic 230 kV and 138 kV Lines	Yes	None	None	None		None
22	Velasco-Century 230 kV Lines 1 & 2	Yes	None	None	None		None
23	Century-Wilmington 138 kV Lines 1 & 2	Yes	None	None	None		None
24	Gramercy-Fairfax 138 kV Lines 1 & 2	Yes	None	None	None		None
25	Century-Gramercy 128 kV Lines 1 & 2	Yes	None	None	None		None
26	Gramercy Tap 1 & Tap 2 138 kV Lines	Yes	None	None	None		None
27	Airport-Fairfax 138 kV Lines 1 & 2	Yes	None	None	None		None
28	Barren Ridge-Haskell Lines 1 & 2	Yes	None	None	None		None
MULTIPLE CONTINGENCIES							
29	Toluca-Hollywood Lines 1,2 & 3	Yes	None	None	None		None
30	Rinaldi-Tarzana Lines 1 & 2 and Northridge-Tarzana Line 1	No	Yes	Yes	Yes		Diverged
31	Rinaldi-Tarzana Lines 1 & 2 and Northridge-Tarzana Line 1 with RAS	Yes	None	None	None		None

2011 Ten Year Plan
Transient & Post Transient Results
2016 Heavy Summer

CONT. NO.	OUTAGE	STABLE	Possible Violations			Post-Transient	
			MORC1	MORC2	FREQ DIP	ΔV>5%	ΔV>10%
(N-1) CONTINGENCY							
1	Adelanto-Rinaldi 500kV line	Yes	None	None	None	None	
2	Adelanto-Toluca 500kV line	Yes	None	None	None	None	
3	Adelanto-Victorville 500kV line	Yes	None	None	None	None	
4	Lugo-Victorville 500kV Line	Yes	None	None	None	None	
5	Victorville-Rinaldi 500kV Line	Yes	None	None	None	None	
6	Mccullgh-Victorville 500kV Line	Yes	None	None	None	None	
7	Mead-Victorville 287 kV Line	Yes	None	None	None	None	
8	Cottonwd-Barren Ridge 230 kV with Remedial Action Scheme (RAS)	Yes	None	None	None	None	
9	Rinaldi-Barren Ridge 230 kV Line						
10	PDCI bipole	Yes	None	None	None	None	
(N-2) CONTINGENCY							
11	IPP DC Bipole	Yes	None	None	None		None
12	Palo Verde-g2-OL-MA-RAS	Yes	None	None	None		None
13	Adelanto-Rinaldi and Victorville-Rinaldi 500 kV Lines	Yes	None	None	None		None
14	McCullgh-Victorville 500 kV Lines 1 & 2	Yes	None	None	None		None
15	Victorville-Century 287 kV Lines 1 & 2						
16	Rinaldi-Tarzana 230 kV Lines 1 & 2	Yes	None	None	None		None
17	Rinaldi-Glendale 230 kV Lines 1 & 2	Yes	None	None	None		None
18	Rinaldi-Valley 230 kV Lines 1 & 2	Yes	None	None	None		None
19	Toluca- Valley 230 kV Lines 1 & 2	Yes	None	None	None		None
20	Glendale-Atwater 230 kV Lines 1 & 2	Yes	None	None	None		None
21	Tarzana-Olympic 230 kV and 138 kV Lines	Yes	None	None	None		None
22	Velasco-Century 230 kV Lines 1 & 2	Yes	None	None	None		None
23	Century-Wilmington 138 kV Lines 1 & 2	Yes	None	None	None		None
24	Gramercy-Fairfax 138 kV Lines 1 & 2	Yes	None	None	None		None
25	Century-Gramercy 128 kV Lines 1 & 2	Yes	None	None	None		None
26	Gramercy Tap 1 & Tap 2 138 kV Lines	Yes	None	None	None		None
27	Airport-Fairfax 138 kV Lines 1 & 2	Yes	None	None	None		None
28	Barren Ridge-Haskell Lines 1 & 2	Yes	None	None	None		None
MULTIPLE CONTINGENCIES							
29	Toluca-Hollywood Lines 1,2 & 3	Yes	None	None	None		None
30	Rinaldi-Tarzana Lines 1 & 2 and Northridge-Tarzana Line 1	No	Yes	Yes	Yes		Diverged
31	Rinaldi-Tarzana Lines 1 & 2 and Northridge-Tarzana Line 1 with RAS	Yes	None	None	None		None

2011 Ten Year Plan

Transient & Post Transient Results

2021 Heavy Summer

CONT. NO.	OUTAGE	STABLE	Possible Violations			Post-Transient	
			MORC1	MORC2	FREQ DIP	ΔV>5%	ΔV>10%
(N-1) CONTINGENCY							
1	Adelanto-Rinaldi 500kV line	Yes	None	None	None	None	
2	Adelanto-Toluca 500kV line	Yes	None	None	None	None	
3	Adelanto-Victorville 500kV line	Yes	None	None	None	None	
4	Lugo-Victorville 500kV Line	Yes	None	None	None	None	
5	Victorville-Rinaldi 500kV Line	Yes	None	None	None	None	
6	Mccullgh-Victorville 500kV Line	Yes	None	None	None	None	
7	Mead-Victorville 287 kV Line	Yes	None	None	None	None	
8	Cottonwd-Barren Ridge 230 kV with Remedial Action Scheme (RAS)	Yes	None	None	None	None	
9	Rinaldi-Barren Ridge 230 kV Line						
10	PDCI bipole	Yes	None	None	None	None	
(N-2) CONTINGENCY							
11	IPP DC Bipole	Yes	None	None	None		None
12	Palo Verde-g2-OL-MA-RAS	Yes	None	None	None		None
13	Adelanto-Rinaldi and Victorville-Rinaldi 500 kV Lines	Yes	None	None	None		None
14	McCullgh-Victorville 500 kV Lines 1 & 2	Yes	None	None	None		None
15	Victorville-Century 287 kV Lines 1 & 2						
16	Rinaldi-Tarzana 230 kV Lines 1 & 2	Yes	None	None	None		None
17	Rinaldi-Glendale 230 kV Lines 1 & 2	Yes	None	None	None		None
18	Rinaldi-Valley 230 kV Lines 1 & 2	Yes	None	None	None		None
19	Toluca- Valley 230 kV Lines 1 & 2	Yes	None	None	None		None
20	Glendale-Atwater 230 kV Lines 1 & 2	Yes	None	None	None		None
21	Tarzana-Olympic 230 kV and 138 kV Lines	Yes	None	None	None		None
22	Velasco-Century 230 kV Lines 1 & 2	Yes	None	None	None		None
23	Century-Wilmington 138 kV Lines 1 & 2	Yes	None	None	None		None
24	Gramercy-Fairfax 138 kV Lines 1 & 2	Yes	None	None	None		None
25	Century-Gramercy 128 kV Lines 1 & 2	Yes	None	None	None		None
26	Gramercy Tap 1 & Tap 2 138 kV Lines	Yes	None	None	None		None
27	Airport-Fairfax 138 kV Lines 1 & 2	Yes	None	None	None		None
28	Barren Ridge-Haskell Lines 1 & 2	Yes	None	None	None		None
MULTIPLE CONTINGENCIES							
29	Toluca-Hollywood Lines 1,2 & 3	Yes	None	None	None		None
30	Rinaldi-Tarzana Lines 1 & 2 and Northridge-Tarzana Line 1	No	Yes	Yes	Yes		Diverged
31	Rinaldi-Tarzana Lines 1 & 2 and Northridge-Tarzana Line 1 with RAS	Yes	None	None	None		None

2011 Ten Year Plan

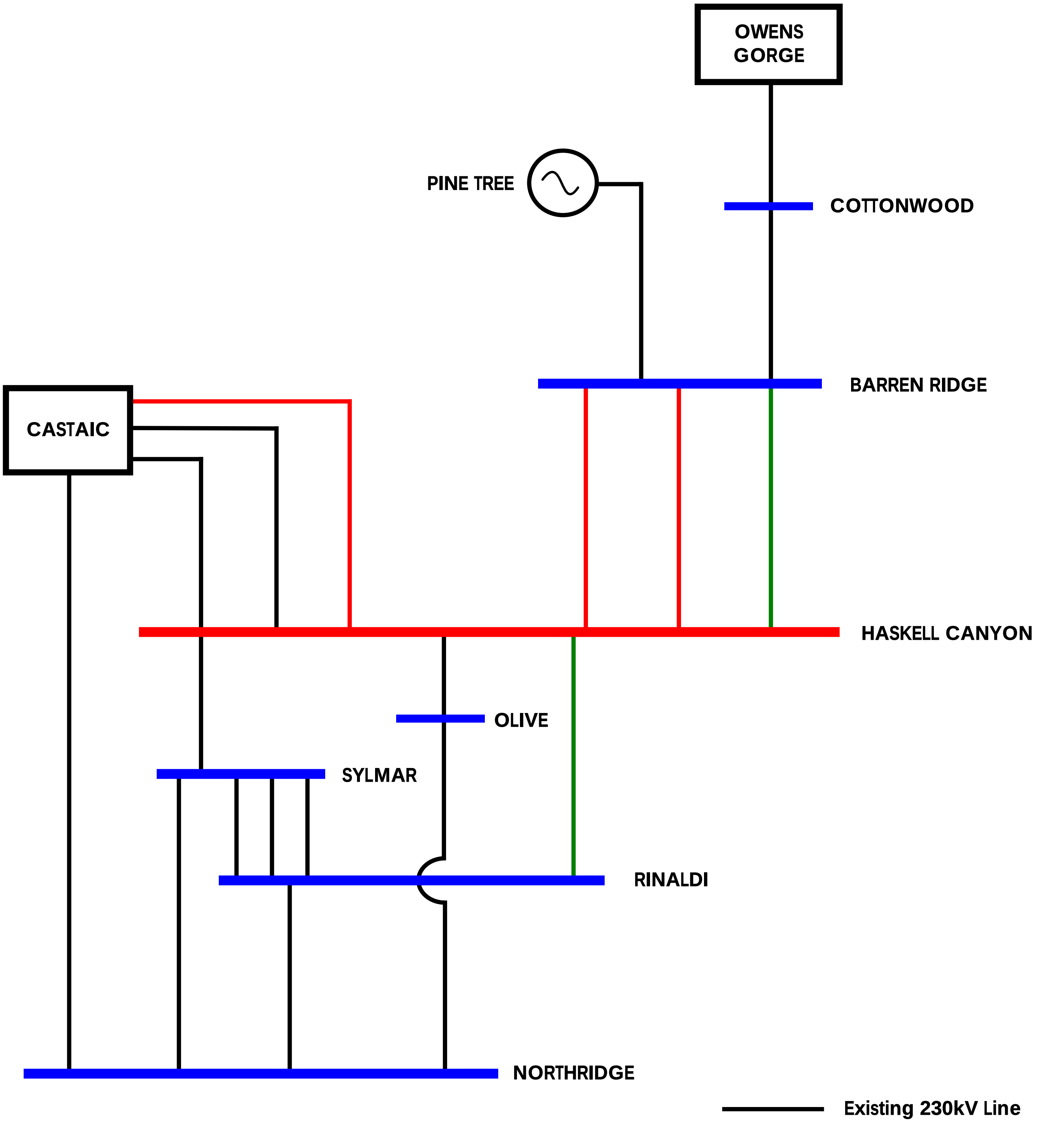
Transient & Post Transient Results

2016 Light Winter

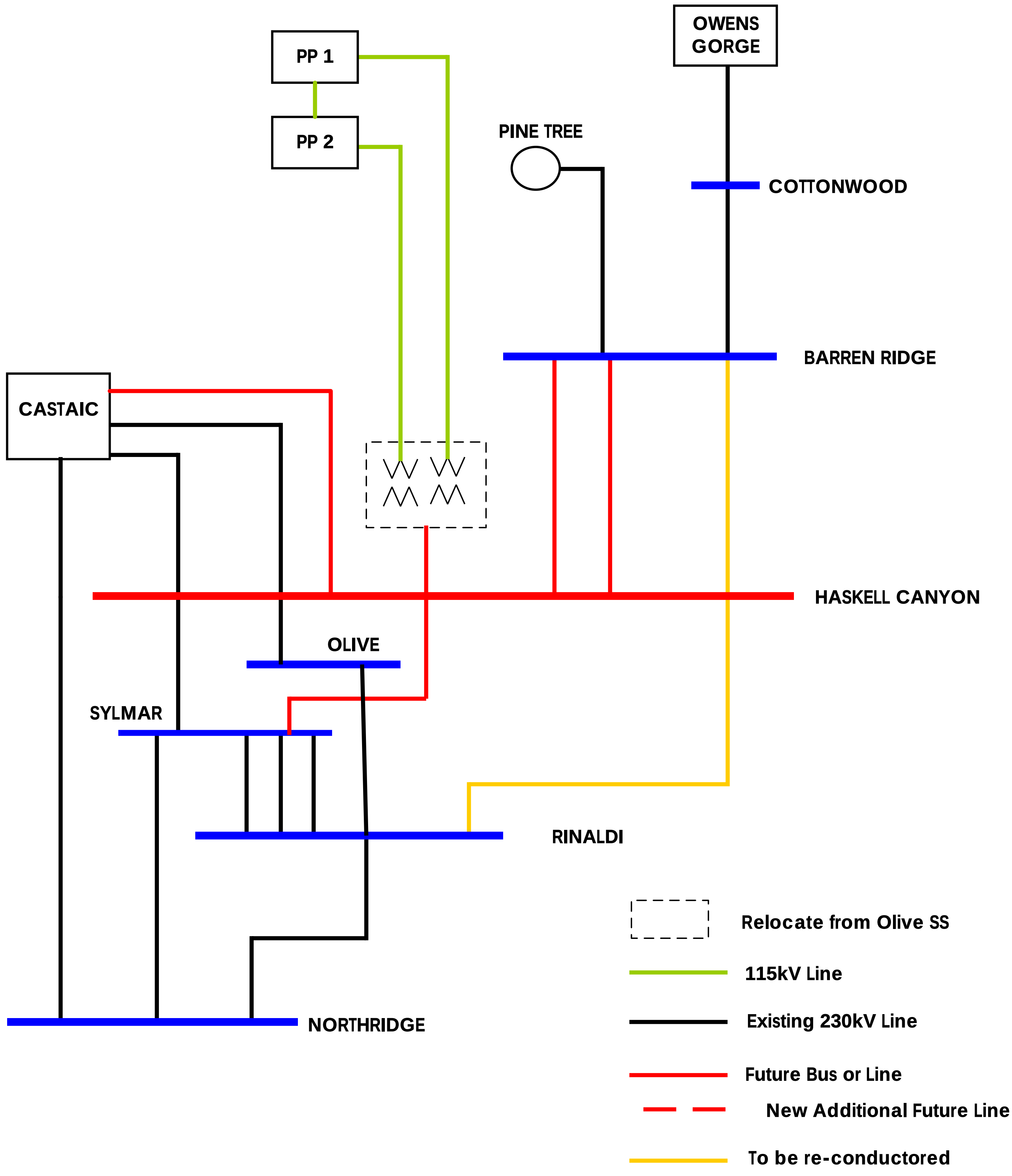
CONT. NO.	OUTAGE	STABLE	Possible Violations			Post-Transient	
			MORC1	MORC2	FREQ DIP	ΔV>5%	ΔV>10%
(N-1) CONTINGENCY							
1	Adelanto-Rinaldi 500kV line	Yes	None	None	None	None	
2	Adelanto-Toluca 500kV line	Yes	None	None	None	None	
3	Adelanto-Victorville 500kV line	Yes	None	None	None	None	
4	Lugo-Victorville 500kV Line	Yes	None	None	None	None	
5	Victorville-Rinaldi 500kV Line	Yes	None	None	None	None	
6	Mccullgh-Victorville 500kV Line	Yes	None	None	None	None	
7	Mead-Victorville 287 kV Line	Yes	None	None	None	None	
8	Cottonwd-Barren Ridge 230 kV with Remedial Action Scheme (RAS)	Yes	None	None	None	None	
9	Rinaldi-Barren Ridge 230 kV Line						
10	PDCI bipole	Yes	None	None	None	None	
(N-2) CONTINGENCY							
11	IPP DC Bipole	Yes	None	None	None		None
12	Palo Verde-g2-OL-MA-RAS	Yes	None	None	None		None
13	Adelanto-Rinaldi and Victorville-Rinaldi 500 kV Lines	Yes	None	None	None		None
14	McCullgh-Victorville 500 kV Lines 1 & 2	Yes	None	None	None		None
15	Victorville-Century 287 kV Lines 1 & 2						
16	Rinaldi-Tarzana 230 kV Lines 1 & 2	Yes	None	None	None		None
17	Rinaldi-Glendale 230 kV Lines 1 & 2	Yes	None	None	None		None
18	Rinaldi-Valley 230 kV Lines 1 & 2	Yes	None	None	None		None
19	Toluca- Valley 230 kV Lines 1 & 2	Yes	None	None	None		None
20	Glendale-Atwater 230 kV Lines 1 & 2	Yes	None	None	None		None
21	Tarzana-Olympic 230 kV and 138 kV Lines	Yes	None	None	None		None
22	Velasco-Century 230 kV Lines 1 & 2	Yes	None	None	None		None
23	Century-Wilmington 138 kV Lines 1 & 2	Yes	None	None	None		None
24	Gramercy-Fairfax 138 kV Lines 1 & 2	Yes	None	None	None		None
25	Century-Gramercy 128 kV Lines 1 & 2	Yes	None	None	None		None
26	Gramercy Tap 1 & Tap 2 138 kV Lines	Yes	None	None	None		None
27	Airport-Fairfax 138 kV Lines 1 & 2	Yes	None	None	None		None
28	Barren Ridge-Haskell Lines 1 & 2	Yes	None	None	None		None
MULTIPLE CONTINGENCIES							
29	Toluca-Hollywood Lines 1,2 & 3	Yes	None	None	None		None
30	Rinaldi-Tarzana Lines 1 & 2 and Northridge-Tarzana Line 1	No	Yes	Yes	Yes		Diverged
31	Rinaldi-Tarzana Lines 1 & 2 and Northridge-Tarzana Line 1 with RAS	Yes	None	None	None		None

Appendix J. Renewable Transmission Expansion Project

BARREN RIDGE RENEWABLE TRANSMISSION PROJECT CONFIGURATION



ULTIMATE BRRTP CONFIGURATION



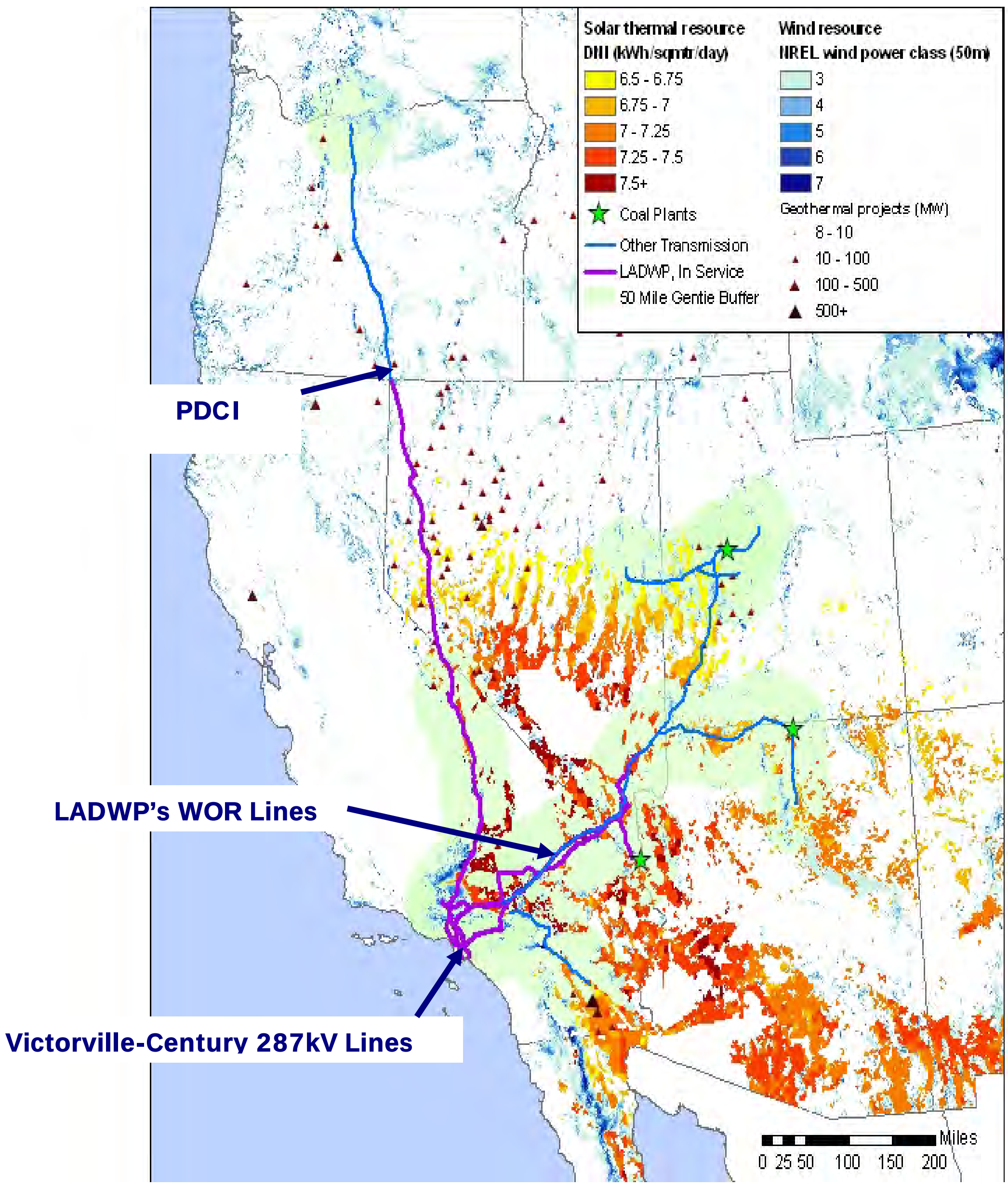
This page is intentionally left blank

Appendix K. Long-Term Transmission Plan

To meet the City's Renewable Portfolio Standard (RPS) goals of 33% by 2020 at the lowest cost, expansion of existing transmission capacity to move greater potential renewable energy resources to load centers are needed. To gain access to these renewable resources and to support the RPS goals, Power System Planning & Development has developed long-term transmission plan which consists of potential upgrade of the existing major transmission lines.

Figure K-1 shows LADWP's major transmission lines connecting to external generating resources along with identified high potential renewable resources.

FIGURE K-1 – LADWP MAJOR TRANSMISION LINES



Three long-term transmission projects are being technically evaluated in the feasibility stage and have demonstrated superior cost effectiveness to meet future transmission needs with minimum environmental impacts. Those are:

1. Upgrade PDCI with hybrid voltage-current enhancement (DC voltage at Sylmar=±495kV DC and DC current = 3410 A)

2. Upgrade Series Compensation of all LADWP's WOR Transmission to 75%

3. Convert the double-circuit Victorville – Century 287 kV AC Lines to ±245kV two spit Voltage Source Controller (VSC) bipole.

Table K-1 summarized the intended benefits of each upgrade

TABLE K-1 INTENDED BENEFITS

LONG-TERM TRANSMISSION PROJECT	EXISTING CAPACITY	POTENTIAL INCREASED CAPACITY	NET CAPACITY INCREASE	BENEFITS
Upgrade PDCI with hybrid voltage-current enhancement	3100 MW	3733 MW	633 MW	Deliver additional amount of renewable wind and hydro energy from the Pacific Northwest to Los Angeles.
Upgrade Series Compensation of all LADWP's WOR Transmission to 75%	3373 MW	TBD	TBD	Deliver additional amount of renewable wind, solar, and geothermal from Wyoming, Utah, Arizona, Nevada, and California desert southwest.
Convert the double-circuit Victorville – Century 287 kV AC Lines to ±245kV two split VSC bipole.	894 MW	1780 MW	886 MW	Increase the power transfer capability from Victorville-Adelanto into the Los Angeles basin area and provide additional voltage support capability.

This page is intentionally left blank

D

[redacted]

This page is intentionally left blank

LADWP 2021
LOCAL CAPACITY TECHNICAL ANALYSIS

Phase 1: High-Load Case Scenario
Phase 2: Mid-Load Case Scenario

FINAL REPORT
AND STUDY RESULTS

February 10, 2012
Redacted Version – November 2012

Local Capacity Technical Study
Overview and Results

I. Executive Summary

This Report documents the results and recommendations of the 2021 Local Capacity Technical (LCT) Studies. The assumptions, processes, and criteria used for the Los Angeles Department of Water and Power's (LADWP) 2021 study mirrors those used in the California Independent System Operator's (CAISO) LCT Studies. LADWP and the CAISO criteria are discussed in the report. The Phase 1 Study (High Case) considers a high capacity need scenario where only LADWP's existing programs in energy conservation, demand-side-management (DSM), Demand Response (DR), and Distributed Generation (DG) are considered. Phase 2 Study (Low Case) considers a low capacity need scenario where aggressive programs in the above outlined items will be addressed.

The 2021 LCT study results are provided to the LADWP Board for their consideration and approval. These results will also be used by the LADWP for identifying the minimum quantity of local capacity necessary to meet the North American Electric Reliability Corporation (NERC) Reliability Criteria used in the LCT Study (this may be referred to as "Local Capacity Requirements" or "LCR") and for assisting in the allocation of costs of any LADWP procurement of capacity needed to achieve the Reliability Criteria.

Below are LADWP's 2021 total LCR:

Table 1a: 2021 Local Capacity Requirements - High-Load Case

	2021 LCR Need Based on Category B [1]			2021 LCR Need Based on Category C with operating procedure		
System Limiting Condition	**Existing Capacity Needed**	**Deficiency in terms of Loadshed needed [2]**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency in terms of Loadshed needed [3]**	**Total Generation Capacity + Loadshed (MW)**
Low PDCI	2077	0 for 2hr	**2077**	3386	150	**3386 + 150**
High PDCI	2777	0 for 2hr	**2777**	3386	358	**3386 + 358**
Total	**2777**	0 for 2hr	**2777**	**3386**	**358**	**3386 + 358**

Table 1b: 2021 Local Capacity Requirements - Mid-Load Case

	2021 LCR Need Based on Category B[1]			2021 LCR Need Based on Category C with operating procedure		
PDCI Flow	**Existing Capacity Needed**	**Deficiency[2]**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency[3]**	**Total (MW)**
High	**2277**	**0 for 2hr**	**2277**	**3386**	**130**	**(3386 + 130) = 3516**

The LADWP Basin LCR Area, which is defined in this analysis, includes all retail load in the Los Angeles basin served by the LADWP, with the exception of load at the Rinaldi Receiving Station which is outside the transmission choke points defining the LCR Area. The load and distributed generation of the municipal utilities of Glendale and Burbank are inside the LCR Area. (LADWP is not assessing the LCR issues for Burbank or Glendale because LADWP has no control over the dispatch of the distributed generation owned by Glendale and Burbank.) This draft study determined that the LCR needs of LADWP are 3,386 megawatt (MW) of generation capacity. This LCR is only 85 MW less than the currently installed LADWP in-basin thermal capacity. By 2021, assuming that all of the existing generation capacity is maintained, a

[1] A single contingency (i.e. Category B) means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

[2] "0 for 2hrs" means that no loadshed is required immediately after the worst Category B contingency because no BES element is loaded in excess of its 2 hour (i.e. emergency) rating; however, loadshed is required after 2 hours to adjust the system so no BES element loaded in excess of its continuous rating.

[3] This deficiency is the loadshed needed after the second of two contingencies to meet the NERC requirement that no element exceed its emergency rating. After meeting this initial performance level by shedding load immediately after the Category C contingency, further loadshed would be needed in the subsequent two hours to restore the system to within normal ratings (rather than emergency ratings).

substantial amount of load shedding programs will be needed to meet the NERC reliability requirement. Short of adding more generation, for this High Case scenario other measures, such as high levels of DSM or DG programs may be needed to avoid load shedding and meet NERC reliability requirements.

Table of Contents

II. Study Overview: Inputs, Outputs and Options

The LADWP incorporated into its 2021 LCT study the same criteria, input assumptions and methodology that were incorporated into CAISO's *2013-15 Local Capacity Technical Analysis: Final Report and Study Results*. December 2010. Instances where the LADWP used different criteria and assumptions are discussed in Section III.

The study assumes that LADWP will achieve the 33% renewable requirements in 2021 based on its 2011 Integrated Resource Plan. We note the LCT requirement is dependent on a variety of assumptions, and these may change over the next decade. For instance, changes to load requirements due to electric vehicle demand will modify the demand forecast, and certain renewable resource that are currently "firmed" may become variable in the future, potentially increasing LCT requirements

A. Objectives

The intent of the 2021 LCT Study is to identify specific areas within the LADWP Balancing Authority Area that have limited import capability and to determine the minimum generation capacity (MW) necessary to mitigate the local reliability problems in those areas

B. Key Study Assumptions

1. LADWP Inputs and Methodology

Two study scenarios are considered for the LCT study. The Phase 1 Study (High Case) considers a high capacity need scenario where only LADWP's existing (and planned) programs in energy conservation, demand-side-management (DSM), Demand Response (DR), and Distributed Generation (DG) are assumed to be in place in 2021. Phase 2 Study (Low Case) considers a lower capacity need scenario where aggressive programs in the above items are assumed to be implemented by 2021.

The following table sets forth a summary of the approved inputs and methodology that have been used in LADWP's 2021 LCT study:

Table 2: Summary Table of Inputs and Methodology Used in this LCT Study

Issue:	How are they incorporated into this LCT study:
<u>Input Assumptions:</u>	
• Transmission System Configuration	The existing transmission system has been modeled, including all projects operational on or before June 1, of the study year and all other feasible operational solutions brought forth by LADWP's system operations group.
• Generation Modeled	The existing generation resources has been modeled and also includes all projects that will be on-line and commercial on or before June 1, of the study year
• Load Forecast	Uses a 1-in-10 year summer peak load forecast
<u>Methodology:</u>	
• Maximize Import Capability	Import capability into the load pocket has been maximized, thus minimizing the generation required in the load pocket to meet applicable reliability requirements.
• QF/Nuclear/State/Federal Units	Regulatory Must-take and similarly situated units like QF/Nuclear/State/Federal resources have been modeled on-line at qualifying capacity output values for purposes of this LCT Study.
• Maintaining Path Flows	Path flows have been maintained below all established path ratings into the load pockets, including the 500 kV. For clarification, given the existing transmission system configuration, the only 500 kV path that flows directly into a load pocket and will, therefore, be considered in this LCR Study is the Victorville/Adelanto transfer path flowing into the LADWP Basin.
<u>Performance Criteria:</u>	
• Performance Level B & C, including incorporation of PTO operational solutions	This LCT Study is being published based on Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. In addition, the LADWP will incorporate all new projects that are in operation before June 1, of the study year and other feasible operational solutions brought forth by LADWP's system operations group. Any such solutions that can reduce the need for procurement to meet the Performance Level C criteria will be incorporated into the LCT Study.
<u>Load Pocket:</u>	
• Fixed Boundary, including limited reference to published effectiveness factors	This LCT Study has been produced based on load pockets defined by a fixed boundary. The LADWP only publishes effectiveness factors where they are useful in facilitating procurement where excess capacity exists within a load pocket.

Further details regarding the 2021 LCT Study methodology and assumptions are provided in Section III, below.

2. CAISO Assumption and Methodology Comparison

As agreed by the study team (California Energy Commission (CEC), CAISO, and LADWP), this LADWP Report uses the techniques developed and used by the CAISO to analyze the Local Capacity Requirements in its analysis, as detailed in the CAISO's "2013-2015 Local Capacity Technical Analysis: Final Report and Study Results, December 2010." By permission of the CAISO, this LADWP Report adopts the format and a substantial amount of language from the CAISO's report, with the intent of making the material easy to review by the California Air Resources Board (CARB) as it works to fairly allocate emission offsets among new or expanded generation units located in the South Coast Air Emission Management District.

LADWP has used the same planning standards as those use by the CAISO in determining the generation capacity requirement.[4] These standards are intended to apply to system planning studies and not system operating studies.[5] See below in Section "VI. Replies to Comments by CEC and CARB Staff" for a comparison of LADWP's planning and operation studies.

Instances where LADWP's criteria and assumptions differ from the CAISO's include:

- In this planning study, LADWP allows loadshed after two hours to restore the system to be within normal ratings (called N-1-adjusted by LADWP), but does not allow further loadshed to adjust for the next contingency (i.e. to prepare for N-1-1). In contrast, the CAISO does not allow any loadshed until the second contingency occurs.
- In this Phase 1 High Load case, LADWP modeled a trajectory case but did not model an environmentally constrained case, while the CAISO modeled both cases. The trajectory case is the currently approved plan while the

[4] See below in this Report in Section III. Assumption Details: How the Study was Conducted, A. System Planning Criteria.

[5] Pg 38, California Environmental Protection Agency Air Resources Board's Report to the Governor and Legislature -- Interim (Phase 1) Report: AB 1318 South Coast Air Basin Electricity Needs Assessment and Permitting Recommendations, July 2010.

environmentally constrained case includes a high level of urban rooftop Photo voltaic Distributed Generation to reflect uncertainty of the severity of environmental constraints involved in building central plant renewable generation resources distant from load centers. Because LADWP has control of these constraints, the study team agreed that the environmentally constrained case did not need to be performed by LADWP.

- No Category C contingencies involving generation tripping were modeled by LADWP in the High case, while they were modeled in by the CAISO. This could cause LADWP's LCR to be underestimated, but not overestimated. The effect on LCR is assumed to be negligible.
- The 2021 CAISO base case was not available for use by LADWP due to time constraints in completing a Non-disclosure agreement. Instead of using the CAISO base case, LADWP used a base case developed in conjunction with the California Transmission Planning Group (CTPG), and the CAISO participated in the development of this base case. After LADWP obtained the CAISO base case, a sensitivity study was run which shows the result to be essentially identical. This is discussed below in the section "VI. Replies to Comments by CEC and CARB Staff".

Instances where LADWP's criteria and assumptions may differ from the CAISO's include:

- No firming of renewable resources by basin thermal generation are modeled in the Phase 1 High Load case. Firming resources would be added on top of LCR resources because the full MW output of the LCR units is needed to manage emergency transmission overloads.
- Cogeneration is assumed off-line in the Phase 1 High Load case in order to assure measurement of total demand by the system. This results in a system load increase of 337 MW in the 2021 model year. A sensitivity case with the cogeneration dispatched in the High-Load Case is described at the end of this document in the section "VIII. Sensitivity Case for

Cogeneration." (The cogeneration was dispatched in the Mid-Load Case by decreasing the load by 337 MW.) Cogeneration dispatch and location is described below in the section "VI. Replies to Comments by CEC and CARB Staff".

- The Mid-Load Case models decreased loads (due to additional EE, DM, and cogeneration) in the same manner as the CAISO. This is discussed below in Section V. "Description of Mid-Load Case".

3. Grid Reliability

Service reliability builds from grid reliability because grid reliability is reflected in the planning standards of the Western Electricity Coordinating Council ("WECC") that incorporate standards set by the North American Electric Reliability Council ("NERC") (collectively "NERC Planning Standards"). The NERC Planning Standards apply to the interconnected electric system in the United States and are intended to address the reality that within an integrated network, actions by one Balancing Authority Area can affect the reliability of other Balancing Authority Areas. Consistent with the mandatory nature of the NERC Planning Standards, the LADWP is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the NERC Planning Standards. Applicable Reliability Criteria consists of the NERC Planning Standards as well as reliability criteria adopted by the LADWP.

The NERC Planning Standards define reliability on interconnected electric systems using the terms "adequacy" and "security." "Adequacy" is the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account physical characteristics of the transmission system such as transmission ratings and the scheduled and reasonably expected unscheduled outages of system elements. "Security" is the ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. The NERC Planning Standards are organized by Performance Categories. Certain categories require that the grid operator not only ensure that grid integrity is maintained under certain adverse system conditions (e.g., security), but also that all customers continue to receive electric supply to meet demand (e.g., adequacy). In that case, grid reliability and service reliability would overlap. But there are other levels of performance where security can be maintained without ensuring adequacy.

4. Application of N-1, N-1-1, and N-2 Criteria

The LADWP will maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Criteria at all times, for example during normal operating conditions (N-0) the LADWP must protect for all single contingencies (N-1) and common mode (N-2) double line outages. Also, after a single contingency, the LADWP must re-adjust the system to support the loss of the next most stringent contingency. This is referred to as the N-1-1 condition.

The N-1-1 vs. N-2 terminology was introduced only as a mere temporal differentiation between two existing NERC Category C events. N-1-1 represents NERC Category C3 ("category B contingency, manual system adjustment, followed by another category B contingency"). The N-2 represents NERC Category C5 ("any two circuits of a multiple circuit tower line") as well as WECC-S2 (for 500 kV only) ("any two circuits in the same right-of-way") with no manual system adjustment between the two contingencies.

5. Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, this LCT Report is based on NERC Performance Level B and Performance Level C criterion. The NERC Standards refer mainly to thermal overloads. However, the LADWP also tests the electric system in regards to the dynamic and reactive margin compliance with the existing WECC standards for the same NERC performance levels. These Performance Levels can be described as follows:

a. <u>Performance Criteria- Category B</u>

Category B describes the system performance that is expected immediately following the loss of a single transmission element, such as a transmission circuit, a generator, or a transformer.

Category B system performance requires that all thermal and voltage limits must be within their "Applicable Rating," (A/R) which, in this case, are the emergency ratings of the lines. Applicable Rating includes a temporal element such that emergency ratings can only be maintained for certain duration. Under this category, load cannot be shed in order to assure the Applicable Ratings are met; however there is no guarantee that facilities are returned to within normal ratings or to a state where it is safe to continue to operate the system in a reliable manner such that the next element out will not cause a violation of the Applicable Ratings.

b. Performance Criteria- Category C

The NERC Planning Standards require system operators to "look forward" to make sure they safely prepare for the "next" N-1 following the loss of the "first" N-1 (stay within Applicable Ratings after the "next" N-1). This is commonly referred to as N-1-1. Because it is assumed that some time exists between the "first" and "next" element losses, operating personnel may make any reasonable and feasible adjustments to the system to prepare for the loss of the second element, including, operating procedures, dispatching generation, moving load from one substation to another to reduce equipment loading, dispatching operating personnel to specific station locations to manually adjust load from the substation site, or installing a "Special Protection Scheme" that would remove pre-identified load from service upon the loss of the "next " element.[6] All Category C requirements in this report refer to situations when in real time

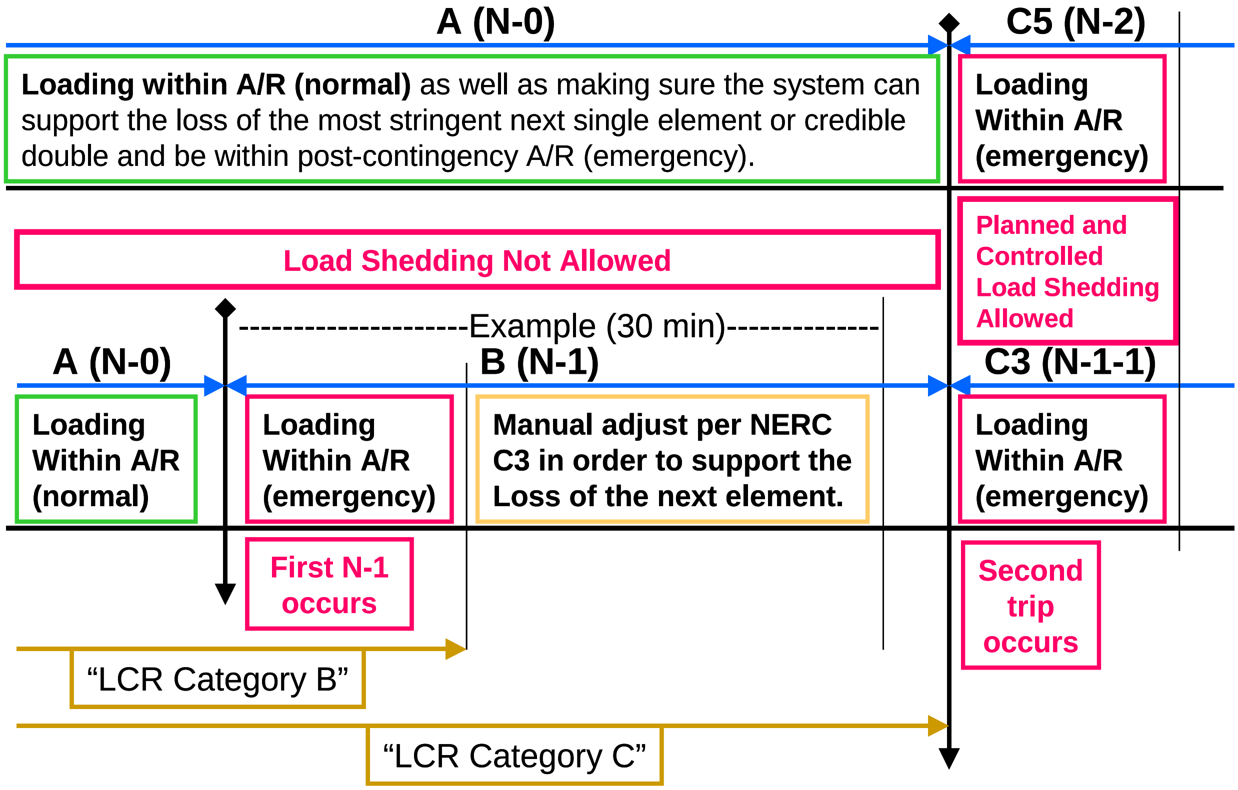
[6] A Special Protection Scheme is typically proposed as an operational solution that does not require additional generation and permits operators to effectively prepare for the next event as well as ensure security should the next event occur. However, these systems have their own risks, which limit the extent to which they could be deployed as a solution for grid reliability augmentation. While they provide the value of protecting against the next event without the need for pre-contingency load shedding, they add points of potential failure to the transmission network. This increases the potential for load interruptions because sometimes these systems will operate when not required and other times they will not operate when needed.

(N-0) or after the first contingency (N-1) the system requires additional readjustment in order to prepare for the next worst contingency. In this time frame, load drop is not allowed per existing planning criteria.

Generally, Category C describes system performance that is expected following the loss of two or more system elements. This loss of two elements is generally expected to happen simultaneously, referred to as N-2. It should be noted that once the "next" element is lost after the first contingency, as discussed above under the Performance Criteria B, N-1-1 scenario, the event is effectively a Category C. As noted above, depending on system design and expected system impacts, the **planned and controlled** interruption of supply to customers (load shedding), the removal from service of certain generators and curtailment of exports may be utilized to maintain grid "security."

c. LADWP Statutory Obligation Regarding Safe Operation

The LADWP will maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Criteria at all times, for example during normal operating conditions **A (N-0)** the LADWP must protect for all single contingencies **B (N-1)** and common mode **C5 (N-2)** double line outages.



Note: the above diagram is for the CAISO; LADWP allows loadshed two hours after a Category B contingency to restore the system to normal ratings.

The following definitions guide the LADWP's interpretation of the Reliability Criteria governing safe mode operation and are used in this LCT Study:

Applicable Rating (A/R) the equipment rating that will be used under certain contingency conditions.

Normal rating is to be used under normal conditions.

Long-term emergency ratings, if available, will be used in all emergency conditions as long as "system readjustment" is provided in the amount of time given (specific to each element) to reduce the flow to within the normal ratings. If not available normal rating is to be used.

Short-term emergency ratings, if available, can be used as long as "system readjustment" is provided in the "short-time" available in order to reduce the flow to within the long-term emergency ratings where the element can be kept for another length of time (specific to each element) before the flow needs to be reduced the below the normal ratings. If not available long-term emergency rating should be used.

Temperature-adjusted ratings shall not be used because this is a 10 year-ahead study not a real-time tool, as such the worst-case scenario must be covered. In case temperature-adjusted ratings are the only ratings available then the minimum rating (highest temperature) given the study conditions shall be used.

LADWP Equipment Rating Handbook is the only official keeper of all existing ratings mentioned above.

Ratings for future projects provided by LADWP's Transmission Planning.

Other short-term ratings not included in the above categories may be used as long as they are engineered, studied and enforced through clear operating procedures that can be followed by real-time operators.

Path Ratings need to be maintained in order for these studies to comply with the Minimum Operating Reliability Criteria and assure that proper capacity is available in order to operate the system in real-time.

Controlled load drop is achieved with the use of a Special Protection Scheme.

Planned load drop is achieved when the most limiting equipment has short-term emergency ratings AND the operators have an operating procedure that clearly describes the actions that need to be taken in order to shed load.

Special Protection Scheme (SPS): all known SPS shall be assumed. New SPS must be verified and approved by the LADWP.

System Readjustment represents the actions taken by operators in order to bring the system within a safe operating zone after any given contingency in the system.

Actions that can be taken as system readjustment after a single contingency (Category B):

1. System configuration change – based on validated and approved operating procedures
2. Generation re-dispatch
    a. Decrease generation
    b. Increase generation – this generation will become part of the LCR need
3. If the lost element cannot be restored, and generation re-dispatch is

insufficient, after two hours loadshed can be used to restore the system to normal ratings.

Actions, which shall not be taken as system readjustment after a single contingency (Category B):

1. Loadshed cannot be used (beyond that mentioned above in bullet 3 to restore the system to normal rating) to prepare for the next contingency.

This is one of the most controversial aspects of the interpretation of the existing NERC criteria because the NERC Planning Standards footnote mentions that load shedding can be done after a category B event in certain local areas in order to maintain compliance with performance criteria. However, the main body of the criteria spells out that no dropping of load should be done following a single contingency. All stakeholders and the LADWP agree that no involuntary interruption of load should be done immediately after a single contingency. After a single contingency, it is understood that the system is in a Category B condition and the system should be planned based on the body of the criteria with no shedding of load regardless of whether it is done immediately or in 15-30 minute after the original contingency. In this planning study, LADWP, in contrast to the CAISO, allows loadshed after two hours to restore the system to be within normal ratings (called N-1-adjusted by LADWP), but does not allow further loadshed to adjust for the next contingency (i.e. to prepare for N-1-1).

A robust transmission system should be, and under the LCT Study is being, planned based on the main body of the criteria, not the footnote regarding Category B contingencies. Therefore, if there are available resources in the area, they are looked to meet reliability needs (and included in the LCR requirement) before resorting to involuntary load curtailment. The footnote may be applied for criteria compliance issues only where there are no resources available in the area.

<u>Time allowed for manual readjustment</u> is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than two hours, based on existing LADWP Planning Standards.

6. The Two Options Presented In This LCT Report

This LCT Study sets forth different solution "options" with varying ranges of potential service reliability consistent with LADWP's Reliability Criteria. The LADWP applies Option 2 for its purposes of identifying necessary local capacity needs and the corresponding potential scope of its backstop authority. Nevertheless, the LADWP continues to provide Option 1 as a point of reference for the CPUC and Local Regulatory Authorities in considering procurement targets for their jurisdictional LSEs.

- **Option 1- Meet Performance Criteria Category B**

Option 1 is a service reliability level that reflects generation capacity that must be available to comply with reliability standards immediately after a NERC Category B given that load cannot be removed to meet this performance standard under Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the **only means** of meeting any Reliability Criteria that is beyond the loss of a single transmission element (N-1). These situations will likely require substantial load interruptions in order to maintain system continuity and alleviate equipment overloads prior to the actual occurrence of the second contingency.[7]

- **Option 2- Meet Performance Criteria Category C and Incorporate Suitable Operational Solutions**

Option 2 is a service reliability level that reflects generation capacity that is needed to readjust the system to prepare for the loss of a second transmission element (N-1-1) using generation capacity *after* considering all reasonable and feasible operating solutions (including those involving customer load interruption)

7 This potential for pre-contingency load shedding also occurs because real time operators must prepare for the loss of a common mode N-2 at all times.

developed and approved by the LADWP. Under this option, there is no expected load interruption to end-use customers under normal or single contingency conditions as the LADWP operators prepare for the second contingency. However, the customer load may be interrupted in the event the second contingency occurs.

As noted, Option 2 is the local capacity level that the LADWP requires to reliably operate the grid per NERC, WECC and LADWP standards. As such, the LADWP recommends adoption of this Option to guide resource adequacy procurement.

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

The following table provides a comparison of system planning criteria, based on the NERC performance standards, used in the study:

Table 3: Criteria Comparison

Contingency Component(s)	NERC Planning Criteria	RMR Criteria	Local Capacity Criteria
A – No Contingencies	X	X	X
B – Loss of a single element			
1. Generator (G-1)	X	X	X[1]
2. Transmission Circuit (L-1)	X	X	X[1]
3. Transformer (T-1)	X	X	X[1,2]
4. Single Pole (dc) Line	X	X	X[1]
5. G-1 system readjusted L-1	X	X	X
C – Loss of two or more elements			
1. Bus Section	X		
2. Breaker (failure or internal fault)	X		
3. L-1 system readjusted G-1	X		(omitted 5)
3. G-1 system readjusted T-1 or T-1 system readjusted G-1	X		(omitted 5)
3. L-1 system readjusted T-1 or T-1 system readjusted L-1	X		X
3. G-1 system readjusted G-1	X		(omitted 5)
3. L-1 system readjusted L-1	X		X
3. T-1 system readjusted T-1	X		X
4. Bipolar (dc) Line	X		
5. Two circuits (Common Mode) L-2	X		X
6. SLG fault (stuck breaker or protection failure) for G-1	X		X
7. SLG fault (stuck breaker or protection failure) for L-1	X		
8. SLG fault (stuck breaker or protection failure) for T-1	X		

9. SLG fault (stuck breaker or protection failure) for Bus section WECC-S3. Two generators (Common Mode) G-2	X X[3]		X
<u>D – Extreme event – loss of two or more elements</u> Any B1-4 system readjusted (Common Mode) L-2 All other extreme combinations D1-14.	X[4] X[4]		X[3]

1 System must be able to readjust to a safe operating zone in order to be able to support the loss of the next contingency.
2 A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.
3 Evaluate for risks and consequence, per NERC standards. No voltage collapse or dynamic instability allowed.
4 Evaluate for risks and consequence, per NERC standards.
5 CAISO tests these contingencies, but LADWP does not; by omitting these contingencies LADWP could underestimate but not overestimate the amount of LCR. The effect is expected to be negligible.

A significant number of simulations were run to determine the most critical contingencies within each Local Capacity Area. Using power flow, post-transient load flow, and stability assessment tools, the system performance results of all the contingencies that were studied were measured against the system performance requirements defined by the criteria shown in Table 4. Where the specific system performance requirements were not met, generation was adjusted such that the minimum amount of generation required to meet the criteria was determined in the Local Capacity Area. The following describes how the criteria were tested for the specific type of analysis performed.

1. Power Flow Assessment:

<u>Contingencies</u>	<u>Thermal Criteria</u>[3]	<u>Voltage Criteria</u>[4]
Generating unit [1, 6]	Applicable Rating	Applicable Rating (Not used by LADWP [8])
Transmission line [1, 6]	Applicable Rating	Applicable Rating
Transformer [1, 6]	Applicable Rating[5]	Applicable Rating[5]
(G-1)(L-1) [2, 6]	Applicable Rating	Applicable Rating (Not used by LADWP [8])
Overlapping [6, 7]	Applicable Rating	Applicable Rating

1 All single contingency outages (i.e. generating unit, transmission line or transformer) will be simulated on local area systems.
2 Key generating unit out, system readjusted, followed by a line outage. This over-

lapping outage is considered a single contingency within the CAISO Grid Planning Criteria. Therefore, load dropping for an overlapping G-1, L-1 scenario is not permitted.

[3] Applicable Rating – Based on LADWP Equipment Rating Handbook or facility upgrade plans including established WECC Path ratings.

[4] Applicable Rating – LADWP Grid Planning Criteria or facility owner criteria as appropriate including established Path ratings.

[5] A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.

[6] Following the first contingency (N-1), the generation must be sufficient to allow the operators to bring the system back to within acceptable (normal) operating range (voltage and loading) and/or appropriate OTC following the studied outage conditions.

[7] During normal operation or following the first contingency (N-1), the generation must be sufficient to allow the operators to prepare for the next worst N-1 or common mode N-2 without pre-contingency interruptible or firm load shedding. SPS may be utilized to satisfy the criteria after the second N-1 or common mode N-2 except if the problem is of a thermal nature such that short-term ratings could be utilized to provide the operators time to shed either interruptible or firm load. T-2s (two transformer bank outages) would be excluded from the criteria.

[8] LADWP did not perform these contingencies. This could cause the LCR to be underestimated, but not overestimated. No effect on the amount or location is expected.

2. Post Transient Load Flow Assessment:

<u>Contingencies</u>	<u>Reactive Margin Criteria</u> [2]
Selected [1]	**Applicable Rating**

[1] If power flow results indicate significant low voltages for a given power flow contingency, simulate that outage using the post transient load flow program. The post-transient assessment will develop appropriate Q/V and/or P/V curves.

[2] Applicable Rating – positive margin based on the higher of imports or load increase by 5% for N-1 contingencies, and 2.5% for N-2 contingencies.

3. Stability Assessment:

<u>Contingencies</u>	<u>Stability Criteria</u> [2]
Selected [1]	**Applicable Rating**

[1] Base on historical information, engineering judgment and/or if power flow or post transient study results indicate significant low voltages or marginal reactive margin for a given contingency.

[2] Applicable Rating – LADWP Grid Planning Criteria or facility owner criteria as

appropriate.

B. Load Forecast

1. System Forecast

For the purpose of conducting system studies, LADWP used its internally-derived the load forecast at the Balancing Authority (BA) levels for 2021, consistent with LADWP system planning assumptions. The CEC also has developed a load forecast for the LADWP balancing authority, which includes assumptions made by CEC regarding system demand and growth, which is not used in this study. The forecast is then distributed across the entire BA, down to the local area, division and substation level. LADWP (as well as CEC) uses an econometric equation to forecast the system load. The predominant parameters affecting the system load are (1) number of households, (2) economic activity (gross metropolitan products, GMP), (3) temperature and (4) increased energy efficiency and distributed generation programs.

The LADWP 1:10 forecast of 6830 MW appears to be a close match to the CEC forecast of 6,784 MW.[8]

2. Base Case Load Development Method

LADWP used a base case developed in conjunction with the California Transmission Planning Group (CTPG) to model the 33% Renewable Portfolio Standard in 2012 across California. The CAISO participated in creating this base case as a member of CTPG.

i. Determination of system loads

The 1:10 system load forecast from LADWP's February 18, 2011 "2011 Retail

[8] The LADWP number includes AC and DC losses; it was not yet ascertained if the CEC forecast also includes AC and DC losses. Reference for CEC forecast:: "Table A-9: Peak Demand by Planning Area (MW), Updated High Forecast" in the CEC "Draft Staff Report, Updated California Energy Demand Forecast May 2011." http://www.energy.ca.gov/2011publications/CEC-200-2011-006/CEC-200-2011-006-SD.pdf

Electric Sales and Demand Forecast" was used for an aggregate load of the entire LADWP Balancing Authority area. In this Heavy Load case, the cogenerators located on the LADWP system are assumed off-line in order to assure measurement of total demand by the system. This results in a system load increase of 337 MW in the 2021 model year. Details of cogeneration dispatch and location, and an evaluation of its effect on the study results, are discussed elsewhere in this report.

ii. Allocation of system load to transmission bus level

The disaggregated (busbar load) is forecast based on the demand characteristics of individual Receiving Stations. This forecast shapes the busbar load to a LADWP Balancing Authority – wide coincidental peak. LADWP uses the annual disaggregated load forecast from LADWP's Distribution Planning group to allocate system load to load busses.

C. Power Flow Program Used in the LCT analysis

The technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program. This GE PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member.

To evaluate Local Capacity Areas, the starting base case was adjusted to reflect the latest generation and transmission projects as well as the one-in-ten-year peak load forecast for the LADWP system. Resource and transmission additions and changes are detailed in Section IV. For the rest of the WECC system the load was kept as in the base case which is based on one-in-five.

Electronic contingency files developed by LADWP were utilized to perform the numerous contingencies required to identify the LCR. These contingency files include remedial action and special protection schemes that are expected to be in operation during the year of study. A LADWP created EPCL (a GE programming language contained within the GE PSLF package) routine was used to run the combination of contingencies.

IV. Local Capacity Requirement Study Results

A. Summary of Study Results

LCR is defined as the amount of generating capacity that is needed within a Local Capacity Area to reliably serve the load located within this area. The results of the LADWP's analysis are summarized in the Executive Summary Tables.

Table 4: 2021 Local Capacity Needs vs. Peak Load and Local Area Generation

Category C	2021 Total LCR (MW)	LCR Area Peak Load (1 in 10) (MW)	High-Load LCR as % of LCR Area Peak Load	Total Dependable Local Area Generation (MW)	2021 LCR as % of Total LCR Area Generation
Haynes	1600	6227	26%	3386	47%
Harbor	466	6227	7%	3386	14%
Scattergood	810	6227	13%	3386	24%
Valley	510	6227	8%	3386	15%
Total	**3386**	**--**	**54%**	**--**	**100%**

Table 5 shows how much of the Local Capacity Area load is dependent on local generation and how much local generation must be available in order to serve the load in those Local Capacity Areas in a manner consistent with the Reliability Criteria. These table also indicate where new transmission projects, new generation additions or demand side management programs may be most useful in order to reduce the dependency on existing, generally older and less efficient local area generation.

Two heavy summer system conditions were studied to capture the range of LCR needed in the LADWP LCR area.

- Minimum PDCI: 600 MW
- Maximum PDCI 3100 MW

B. High-Load Case, Minimum PDCI System Limitation Condition

This condition is where the PDCI is minimum of about 600 MW while at the same time the LADWP import on Victorville/Adelanto to Los Angeles and the Castaic/Barren Ridge flow to the Los Angeles basin are the highest. The total resources needed in each the two timeline issues are:

Table 5: High-Load Case, 2021 Local Capacity Requirements: Minimum PDCI System Limitation

Basin Thermal Generation	Capacity	Category B	Category C
Haynes	1619 MW	740 MW	1600 MW
Harbor	466 MW	227 MW	466 MW
Scattergood	810 MW	600 MW	810 MW
Valley	576 MW	510 MW	510 MW
Total	**3471 MW**	**2077 MW**	**3386 MW**
[redacted]	[redacted]	[redacted]	[redacted]

C. High-Load Case, Maximum PDCI System Limitation Condition

This condition is where the PDCI is maximum of 3100 MW while at the same time the LADWP import on Victorville/Adelanto to Los Angeles and the Castaic/Barren Ridge flow to the Los Angeles basin are the lowest. The total resources needed in each the two timeline issues are:

Table 6a: High-Load Case, 2021 Local Capacity Requirements: Maximum PDCI System Limitation

Basin Thermal Generation	Capacity	Category B	Category C
Haynes	1619 MW	1440 MW	1600 MW
Harbor	466 MW	227 MW	466 MW
Scattergood	810 MW	600 MW	810 MW
Valley	576 MW	510 MW	510 MW
Total	**3471 MW**	**2777 MW**	**3386 MW**
[redacted]	[redacted]	[redacted]	[redacted]

D. Mid-Load Case, Maximum PDCI System Limitation Condition

This condition is same as above for the High-Load Case with Maximum PDCI. (No Minimum PDCI case was run for the Mid-Load Case.) The total resources needed in each the two timeline issues are:

[9] "0MW for 2hrs" means that no loadshed is required immediately after the worst Category B contingency because no BES element is loaded in excess of its 2 hour (i.e. emergency) rating; however, loadshed is required at 2 hours to adjust the system so no BES element loaded in excess of its continuous rating.

Table 6b: Mid-Load Case, 2021 Local Capacity Requirements: Maximum PDCI System Limitation

Basin Thermal Generation	Capacity	Category B	Category C
Haynes	1619 MW	1440 MW	1600 MW
Harbor	466 MW	227 MW	466 MW
Scattergood	810 MW	600 MW	810 MW
Valley	576 MW	510 MW	510 MW
Total	**3471 MW**	**2777 MW**	**3386 MW**
[redacted]	[redacted]	[redacted]	[redacted]

E. Total System LCR Requirement (High-Load and Mid-Load Cases)

Total Local Capacity Requirement is determined by also achieving the requirements of each system limitation condition. Because these areas are a part of the interconnected electric system, the total system requirement is the maximum of all of the requirements.

Table 7: High-Load Case and Mid-Load Case, 2021 Local Capacity Requirements: Meeting both Minimum and Maximum PDCI System Limitations

Basin Thermal Generation	Capacity	Category B	Category C
Haynes	1619 MW	1440 MW	1600 MW
Harbor	466 MW	227 MW	466 MW
Scattergood	810 MW	600 MW	810 MW
Valley	576 MW	510 MW	510 MW
Total	**3471 MW**	**2777 MW**	**3386 MW**
[redacted]	[redacted]	[redacted]	[redacted]

Load shed for these LCR contingencies is location specific. In this report, load shed is only modeled at the busses immediately downstream[11] of the overloaded transmission line, however the effectiveness of LA Basin-wide demand reduction can be estimated by comparing the High-Load Case to the Mid-Load Case: for the most limiting contingencies, 2.7 MW load reduction spread across the LA Basin is equivalent to 1 MW of loadshed at the busses immediately downstream of the overloaded transmission

10 [redacted]

11 [redacted].

element.[12]

The efficacy of Demand Response to decrease the amount of loadshed is not well defined at this time due to the uncertainties regarding these programs, as discussed in the section for the Mid Load Case.

V. Description of Mid-Load Case

The Mid Load case is created from the High Load Case by scaling down the LADWP loads by 626 MW. This represents (a) an decrease of load by 373 MW to represent increased Energy Efficiency plus (b) an decrease in load of 337 MW to represent cogeneration dispatched [13] plus (c) a 74 MW increase in load as a correction [14] to the forecast of rooftop urban Photo Voltaic distributed generation.

The 373 MW of increased Energy Efficiency is the "Advanced Program" which is part of a presentation to the LADWP Board from December 6, 2011; it represents an 8.6% increase from the baseline forecast by the year 2020. The allocation to individual load busses was done by using the distribution factors developed by the CEC and the San Diego Gas and Electric company: Residential 63%, Commercial 34% and Industrial 3%. (Assessing Impacts of Incremental Energy Efficiency Program Initiative on Local Capacity Requirements, CEC, November 4, 2011)

Increased Demand Response (DR) was not modeled in the Mid Load case because of uncertainty of the amount and effectiveness of DR. The mix of technologies in DR programs make it difficult to estimate their effectiveness and amount – i.e. it is hard to estimate how quickly customers can respond to signals to drop load, how often they would respond to requests to drop load, and how much customer acceptance can be

[12] Comparing the High Load and Mid Load cases, scaling load by 626 MW decreased loadshed by 229 (=358-130) MW; in other words, a 2.7 MW load reduction results in 1 MW loadshed reduction.

[13] The cogeneration dispatch is described in section "VI. Replies to Comments by CEC and CARB Staff ".

[14] The 74 MW of urban rooftop Photo Voltaic distributed generation is 50% of the nameplate 148 MW target for the year 2020; it is scaled by 50% to model the 4:00 pm peak, where the 148 MW value is the maximum production at noon.

achieved.

Only existing cogeneration was modeled because (a) LADWP has seen no growth in cogeneration customers and (b) the State cogeneration initiative is still in-development. The State cogeneration initiative would help increase cogeneration by decreasing today's restrictions that limit the amount that cogeneration generation can exceed the customer's load.

These assumptions were agreed on with the study team. CEC staff communicated that the CAISO performed sensitivity studies to see if increased DR could off-set LCR needs in certain locations. LADWP has not performed any similar studies to see if loadshed could be off-set by increased DR.

VI. Replies to Comments by CEC and CARB Staff

Comments by CEC and CARB Staff on LADWP's October 31, 2011 draft LCR Report (in italic) (page references in Italic refer to the October 31 Draft)

<u>Oral Discussion Items from November 8</u>

"1. Page 2, please add to the text or create a footnote differentiating this planning study from the operating study submitted to SWRCB in Feb. 2011.

> The values for "Category B" in Table 1 correspond to the LADWP operating study value for "minimum basin generation required for continuous security" in the LADWP 2010 Summer Assessment, provided to the State Water Board February 2011, with one caveat: Category B does not require generation be adjusted to restore loading and voltages to be within normal ratings. The 2010 Summer Assessment does require that adjustment; the resulting LCR value is called N-1-adjusted in the following discussion.
>
> The LCR values for "Category C" in Table 1 include N-1-adjusted. The LCR value for N-1-adjusted is determined during the simulation of the Category C contingency called N-1-1. N-1-1 means lose one line, adjust the system (resulting in the N-1-adjusted LCR value as in the Summer Assessment) and then lose another line, resulting in the N-1-1 LCR value. The required LCR and loadshed are calculated in two stages: first for N-1-adjusted, and subsequently for N-1-1.

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

For N-1-adjusted, a single line is tripped-off, and LCR dispatch and loadshed is used to relieve overloads to restore the system to its *continuous* thermal ratings. This adjustment is not preparation for the next contingency, it is only to lower the line loading to meet continuous ratings instead of emergency ratings.

For N-1-1, the N-1-adjusted case has an additional line tripped-off, and loadshed is used to relieve overloads to restore the system to its *emergency* thermal ratings. For the N-1-1 contingencies, only loadshed could be used to relieve overloads because all LCR units were already dispatched in the N-1-adjusted calculation.

[redacted]

"2. Page 7, incomplete sentence "In addition, the LADWP will incorporate all new projects that are in operation before June 1, of the study year and other feasible operational solutions brought forth by LADWP's system operations group or. Any such solutions that can reduce the need for procurement to meet the Performance Level C criteria will be incorporated into the LCT Study." From the discussion on the conference call, it sounds like the report does not address the solutions that can reduce the need for procurement (or load shed). It sounded like LADWP may consider reconductoring where load shed is needed. Will this and any other possible solutions be added to the report?

[redacted]

"3. Page 8, please clarify the scope of this study as addressing emission offsets from new or expanded generators.

We confirm that the scope of this study is limited to addressing the need for emission offsets from new or expanded generators.

"4. Page 9, please clarify to what extent renewable firming resources (acknowledged to be additive to LCR needs) can be located outside of the geographic boundaries of the South Coast Air Basin, and thus do not require emission reduction credits or credits from SCAQMD's internal bank pursuant to Rule 1315.

This has not been determined at this time.

"5. Page 9, please augment the discussion of treating cogeneration as not dispatched and spreading the increase in load proportionally across all load busses and the consequences of this approach on the results obtained.

The original DWP forecast had 337 MW of cogeneration, distributed to individual load banks. The High Load was made by scaling up load in the original forecast by 337 MW to model cogeneration as not dispatched. The Mid Load was made by reversing the scaling by 337 MW.

The effect of spreading the load increase (to create the High Load Case) proportionally across all load busses (rather than scaling down each bus according to its individual cogeneration components) is captured in the spread between the High Load Case and the Mid Load Case. The reason for this is (1) the Mid Load Case restores the individual cogeneration forecast by load bank and (2) both Cases require loadshed due to lack of generation located in the LADWP LA Basin LCR Area. There are no consequences of this approach that affect the results obtained: all LADWP generation in the Area is needed for LCR, regardless of how the cogeneration is modeled.

Simultaneous fine tuning of (a) forecasts for the 337 MW cogeneration to show gross cogeneration generator output rather than cogeneration load (which is 40 MW smaller than cogeneration generator output), and (b) forecasts for rooftop PV to account for lower output at the 4:00 pm system peak load, shows that using the value of 337 MW for cogeneration would cause the High Load Case load case to be 43 MW too high and the Mid Load Case load to be 74 MW too low. The 74 MW correction was made to the Mid-Load case, but no correction was made to the High-Load case. The consequences are estimated as 16 MW too high load shed in the High-Load case due to the extra 43 MW of load.[15] This is discussed further below in the response to question 11.

"6. Page 24, please describe the rationale for the loads at Rinaldi to not be included in the defined area.

The overloads requiring LCR generation are "downstream" of Rinaldi: power flows through the Rinaldi bus into the load pocket (toward Valley/Toluca or toward Tarzana). Because of this, the load level at Rinaldi does not influence LCR simulations, and loadshed at Rinaldi is not useful to mitigate LCR contingencies.

"7. Page 26, please add to the discussion an explanation like that provided on the conference call that LADWP is required to dispatch resources to overcome the

[15] Comparing the High Load and Mid Load cases, scaling load by 626 MW decreased loadshed by 229 MW; in other words, a 2.7 MW load reduction results in 1 MW loadshed reduction. Using this ratio, the High Load case has 16 MW too high loadshed.

consequences on its system of other's usage of the PDCI.

The difference between the High-PDCI case and the Low-PDCI case represents the burden on LADWP due to other's usage of the PDCI. In Table 5, this burden is an increase in loadshed of 208 MW (=358-150).

<u>New Items Not Discussed November 8</u>

"1 Table 1 on page 3, are the deficiency numbers reversed? 318 MW of load shed corresponds to High PDCI according to Table 6 and 150 MW of load shed corresponds to Low PDCI according to Table 5.

Yes. Table 1 is corrected.

"2 Page 9, it may be helpful to highlight some of the key assumptions, such as load and OTC assumptions, between the CTPG and CAISO base case to verify that differences are minimal.

The LADWP load and OTC assumptions are identical in the LADWP case and the CAISO case. Both cases have 6227 MW at the load buses in the Area. In both cases, all LA Basins thermal generating units (including all OTC units) were needed to mitigate overloads, and, in both cases, this amount of generation was insufficient, and load shed was needed.

Results for CAISO vs. CTPG comparison are:

- o same LCR generation is needed in both cases
- o 41 MW more loadshed is needed in the CAISO case (400 vs. 359)

This comparison is sufficient to show that the two cases provide essentially the same results. The comparison of these cases is discussed further above in the response to the first comment.

"3. Page 16-17, please consider whether the discussion of the "option" to only pursue Category B is actually allowed by FERC/NERC/WECC standards.

In the Operating Horizon, LADWP uses a Category B criteria with the caveat that the system is restored to within continuous rating in two hours. This is discussed above in the response in this section.

In the Operating Horizon, the CAISO requires that SCE use generation (instead of loadshed) to meet most contingencies in Category C.

It appears that LADWP would also move to match the CAISO's higher performance level (Category C) if LADWP was in the same Balancing Authority Area as the CAISO.

"4. Page 19, what is the reference for footnote 8?

LADWP did not simulate contingencies involving loss of a generator (Category B) or the loss of a transmission line and generator with the system adjusted between the loss of the two elements (Category C).

"5. Page 20, the study references the CEC forecast, and it would be interesting to see how LADWP's forecast compares to the CEC forecast. Maybe a footnote with the comparison could be added.

The LADWP 1:10 forecast of 6830 MW appears to be a close match to the CEC forecast of 6,784 MW. The LADWP number includes AC and DC losses; it was not yet ascertained if the CEC forecast also includes AC and DC losses. Reference for CEC forecast: "Table A-9: Peak Demand by Planning Area (MW), Updated High Forecast" in the CEC "Draft Staff Report, Updated California Energy Demand Forecast May 2011." http://www.energy.ca.gov/2011publications/CEC-200-2011-006/CEC-200-2011-006-SD.pdf

"6. Page 21, it would be helpful to have a link to the "2011 Retail Electric Sales and Demand Forecast" assuming that this is available on the internet.

Not available at this time.

"7. Page 21, what is the method and where can results be found for allocation of system load to load busses.

LADWP uses the annual disaggregated load forecast from LADWP's Distribution Planning group to allocate system load to load busses.

"8. Page 22-23, please expand the discussion referencing these tables to address the finding that load shed is needed to satisfy contingencies, and clarify where that load shed ought to occur if any location is preferable compared to others. Please clarify whether this load shed can be accomplished through demand response programs or whether the immediacy of response requires that firm load be interrupted

Load shed for these LCR contingencies is location specific. In this report, load shed is only modeled at the busses immediately downstream[16] of the overloaded transmission line, however the effectiveness of LA Basin-wide demand reduction can be assessed by comparing the High-Load Case to the Mid-Load Case: 2.7 MW load reduction spread across the LA Basin is equivalent to 1 MW of loadshed at the busses immediately downstream of the overloaded transmission element.[17]

[16] [redacted].

[17] Comparing the High Load and Mid Load cases, scaling load by 626 MW decreased loadshed by 229 MW; in other words, a 2.7 MW load reduction results in 1 MW loadshed reduction.

The efficacy of Demand Response to decrease the amount of loadshed is not well defined at this time due to the uncertainties regarding these programs, as discussed in the section for the Mid Load Case.

"9. Page 24, can you elaborate on what it means to include Glendale and Burbank in the LADWP Basin Area definition, but not calculate their LCR?

LADWP has no control over the dispatch of the distributed generation owned by Glendale and Burbank.

"10. Page 24, please formalize the table at the bottom of the page and add a column providing the rationale for additions and subtractions to net peak load (NPL).

Done

"11. Page 25, please add the specific cogen unit capacities to this listing of resources. Shouldn't the capacities of Burbank and Glendale units assumed to be dispatched at 1:10 peak load conditions also be added?

LADWP has no control over the dispatch of the distributed generation owned by Glendale and Burbank.

For Burbank and Glendale modeling in this study, the CTPG case has 22 MW more generation and 0.5 MW less load than the recently approved WECC case for Heavy Summer 2021 (21hs1a2, posted at WECC 5/11/2011.)

After close examination of the cogeneration forecast, it was found that the load in the High Load Case is 43 MW too high because of a mistake in interpretation of "cogen" in the forecast. The forecast cogen was interpreted as 337 MW of gross cogeneration generation output. However, the 337 MW value was composed of 189 MW of cogeneration load (instead of gross generation) plus (inadvertently) 148 MW of PV DG. The cogeneration forecast should be corrected downward to reflect only the 220 MW of dispatched cogeneration plus non-PV DG and no PV DG. Apart from the cogeneration, both the High-Load Case and the Mid-Load case should also have their load adjusted downward by 74 MW to correct the PV DG forecast to show 50% of the nameplate 148 MW of PV DC generating at 4:00 pm. (220+74=294; 337-294=43)

The cogeneration generator output at the system peak is 220 MW from the from the nameplate capacity of 296 MW. This 220 WM is composed of (a) 180 MW CHP serving cogeneration native load plus (b) 40 MW excess cogeneration and non-PV distributed generation.

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	

[redacted]

"12. Pages 29-30 need to be better integrated into the body of the report or clearly set aside as an attachment referred to in the body of the report.

These pages were deleted because they did not add useful analysis to the report.

Additional Questions from ARB Staff

"1. On the call you mentioned you expect more thermal generation may be needed to firm up renewables. From what we understand, this is generation above LCR requirements. As the trajectory case is based on currently approved plans and you know your RPS profile in 2020, can you estimate the MW and capacity factors needed for any firming generation that needs to be located in-basin?

This has not been determined at this time.

"2 PM2.5 is not covered by the SCAQMD Rule 1304 offset exemption for repowers. Is taking a 100 tpy PM2.5 emissions cap to avoid offsets expected to result in any significant operating constraints on existing units or projected capacity factors needed for repowered units? Based on installed MW, we expect this might only be an issue at the Haynes facility?

No, taking a 100 tpy PM2.5 emissions cap is not expected to result in any significant operating constraints on existing units or on the projected capacity factors for the repowered units.

VII. LCR for the LADWP Basin Area

Area Definition

[redacted]

These sub-stations form the boundary surrounding the LADWP Basin area:

[redacted]

The municipal utilities of Glendale and Burbank are included in this Area but their LCR requirement is not calculated. LADWP has no control over the dispatch of the distributed generation owned by Glendale and Burbank

Load at the Rinaldi Receiving Station is not in this Area. The overloads requiring LCR generation are “downstream” of Rinaldi: power flows through the Rinaldi bus into the load pocket (toward Valley/Toluca or toward Tarzana). Because of this, the load level at Rinaldi does not influence LCR simulations, and loadshed at Rinaldi is not useful to mitigate LCR contingencies.

Total 2021 busload within the defined area for the High-Load Case is 6226 MW.

For the High-Load Case, cogeneration is assumed to not be dispatched.

1:10 NPL	6830
Cogen	337
1:10 Gross	7167

To get the load in the LA Basin at the bus-bars:

1:10 Gross	7167

transmission losses + Owens Valley load	611
LA Basin busbar load	6556

To get the load in the LRA area:

LA Basin busbar load	6556
Rinaldi load	330*
LCR Area busbar load	6226

* Rinaldi load is 343 prior to scaling down for cogen, and 330 after scaling down for cogen.

Total units and qualifying capacity available in the LA Basin area:

Resource	Bus #	Bus Name	kV	NQC	Unit ID
Harbor 1	[redacted]	HARB1G	[redacted]	82	[redacted]
Harbor 2	[redacted]	HARB2G	[redacted]	82	[redacted]
Harbor 5	[redacted]	HARB5G	[redacted]	65	[redacted]
Harbor 10	[redacted]	HARBCT10	[redacted]	47.4	[redacted]
Harbor 11	[redacted]	HARBCT11	[redacted]	47.4	[redacted]
Harbor 12	[redacted]	HARBCT12	[redacted]	47.4	[redacted]
Harbor 13	[redacted]	HARBCT13	[redacted]	47.4	[redacted]
Harbor 14	[redacted]	HARBCT14	[redacted]	47.4	[redacted]
Haynes 1	[redacted]	HAYNES1G	[redacted]	222	[redacted]
Haynes 2	[redacted]	HAYNES2G	[redacted]	222	[redacted]
Haynes 8	[redacted]	HAYNES8G	[redacted]	250	[redacted]
Haynes 9	[redacted]	HAYNES9G	[redacted]	162.5	[redacted]
Haynes 10	[redacted]	HAYNS10G	[redacted]	162.5	[redacted]
Haynes 11	[redacted]	HYN1112G	[redacted]	100	[redacted]
Haynes 12	[redacted]	HYN1112G	[redacted]	100	[redacted]
Haynes 13	[redacted]	HYN1314G	[redacted]	100	[redacted]
Haynes 14	[redacted]	HYN1314G	[redacted]	100	[redacted]
Haynes 15	[redacted]	HYN1516G	[redacted]	100	[redacted]
Haynes 16	[redacted]	HYN1516G	[redacted]	100	[redacted]
Scattergood 1	[redacted]	SCATT1G	[redacted]	150	[redacted]
Scattergood 2	[redacted]	SCATT2G	[redacted]	150	[redacted]
Scattergood 4	[redacted]	SCATT4ST	[redacted]	210	[redacted]
Scattergood 5	[redacted]	SCATT5GT	[redacted]	100	[redacted]
Scattergood 6	[redacted]	SCATT6GT	[redacted]	100	[redacted]
Scattergood 7	[redacted]	SCATT7GT	[redacted]	100	[redacted]
Valley 5	[redacted]	VALLEY5G	[redacted]	47	[redacted]
Valley 6	[redacted]	VALLEY6G	[redacted]	157	[redacted]
Valley 7	[redacted]	VALLEY7G	[redacted]	157	[redacted]
Valley 8	[redacted]	VALLEY8G	[redacted]	215	[redacted]

Major new projects modeled:

1. Repowering of several units in the LADWP Basin Local Capacity Area were modeled, but the change in MW capacity and location are essentially unchanged.
2. In the LADWP Basin Local Capacity Area, several upgrades were added

to relieve transmission bottlenecks (to meet Category C performance criteria) and to add to reliability (Category D loss of an entire Receiving Station):

[redacted]

3. In the LADWP Basin Local Capacity Area, wind and solar generation interconnections along with related transmission additions/upgrades were added:

[redacted]

Critical Contingency Analysis Summary

LADWP Basin Area:

There are two critical conditions for LCR analysis in the LADWP Basin; (1) high Pacific DC Intertie (PDCI) flows, and (2) low PDCI flows. This range of PDCI flows is required because (a) the PDCI is more than 50% owned by CAISO Participating Transmission Owners (SCE, Pasadena), and (b) FERC requires that LADWP must sell any LADWP-owned PDCI capacity on the LADWP OASIS unless the capacity is reserved (under strict rules) for the use of LADWP's native load customers. These constraints on LADWP's control over the PDCI means that LADWP cannot forecast the PDCI schedule because the overwhelming majority of PDCI schedule changes are driven hour-by-hour by others' market choices. The LCR requirement for the High PDCI case is overlapped with the Low PDCI case to provide the LADWP Basin overall LCR requirement.

The most critical contingencies for the LADWP Basin Area are:

[redacted]

[redacted]

[redacted]

[redacted]

Effectiveness factors:

All currently planned generation is included in the LCR total of [redacted], and several hundred MW of planned loadshed is still required. Because this deficit leave no options to pick between generation units to provide LCR capacity, no effectiveness factors are provided.

LA Basin Overall Requirements:

2021	QF/Wind (MW)	Nuclear (MW)	LADWP (MW)	Max. Qualifying Capacity (MW)
Available generation	0	0	3471	3471

High-Load Case 2021	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need (Generation + Loadshed)
Category B (Single)[18]	2777	**0 for 2 hr**	**2777 + 0**
Category C (Multiple)[19]	3386	**0 for 2 hr**	**3386 + 358**

Mid-Load Case 2021	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need (Generation + Loadshed)
Category B (Single)[20]	Not calculated		
Category C (Multiple)[21]	3386	**0 for 2 hr**	**3386 + 130**

VIII. Sensitivity Case for Cogeneration

Cogeneration is assumed off-line in the Phase 1 High Load case in order to assure measurement of total demand by the system. A sensitivity case is provided with the forecast 337 MW of cogneration modeled in-service (i.e. scaling down LADWP load by 337 MW.) This sensitivity case showed that at least 80 MW of loadshed would still be needed, in addition to all existing basin thermal units, to provide an acceptable level of system performance. [redacted]. This was not the worst contingence, so more than 80 MW of loadshed would likely be needed.

[18] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[19] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[20] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[21] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

This page is intentionally left blank

[redacted]

F

[redacted]

This page is intentionally left blank

Questions and Answers

1. What happens if LADWP does not have the stated required amount of generation?

Without the required generation, LADWP may have to interrupt customer service following events that typically occur on the system, such as loss of a generator or transmission. This would expose customers to more frequent and longer duration outages. Industry mandatory reliability standards and prudent utility practices require that utilities not interrupt customers for these typical events. In addition, LADWP is mandated by its City Charter to provide reliable electric service.

2. Why can't LADWP construct new interconnections to meet power demand requirements?

New interconnections would require a right-of-way for the transmission line and space for station equipment, neither which is readily available. In addition, power may not flow on new interconnections as desired, and could aggravate the problem without costly specialized equipment. Transmission changes require a long lead time and could in fact delay the OTC compliance schedule.

3. Why not build more transmission to get rid of transmission bottlenecks so the LA Basin can be served by out-of-basin resources?

Los Angeles is a metropolitan area. The current transmission corridors are boxed in by commercial and residential property in many areas. There is no room to expand these existing corridors and no place to create new corridors. Upgrading the existing lines would require either wider corridors (not available) or total reconstruction of the existing lines and towers. The latter would be extremely costly, require extensive construction along the way, and would place the system at risk during the construction- subjecting customers to potentially lengthy outages if an adjacent circuit or local generator was lost.

4. Why can't the CAISO supply the needed generation?

Joining the CAISO would not change the way power flows on the transmission circuits. LADWP would still need the generation in the existing locations.

5. Is it absolutely necessary that LADWP keep the Basin generation in operation to maintain reliability?

Engineering studies demonstrate that local area generation is vital to providing reliable power to consumers. This need will increase as LADWP divests coal resources and adds renewable energy.

6. Would LADWP meet NERC planning reliability requirements if any significant level of the OTC Basin generation is shutdown forever?

Engineering studies demonstrate that all basin generation is needed to meet NERC Reliability Standards and this need grows in subsequent years.

7. Would LADWP meet NERC planning reliability requirements if any significant level of the OTC Basin generation is not available for extended periods of time, including summary peak periods (two to three years) to repower in place (decommission, demolish, cleanup, and rebuild) Basin OTC units?

All basin generation is required for reliability during the peak load period which typically runs from July through September, but all may be necessary outside this period, as Southern California is prone to late spring and early fall unseasonal heat waves. During the non-summer period, all generators undergo a maintenance period to prepare them for the following summer. If some units are removed for a long period of time, it may not be possible to perform needed maintenance on the other units and still maintain reliable operation.

8. Does LADWP run a risk of violating NERC reliability requirement if any of the proposed 2029 end date for the OTC repowering time line is condensed by a few years?

LADWP must construct and place in service new generation of equivalent capacity and location, prior to decommissioning any generation. Due to limited real estate at the current generation sites, some existing units must be demolished after their replacement is constructed prior to commencing the next repower project. Further condensing of the schedule would likely require beginning demolition prior to placing new units on line. This would make it impossible for LADWP to meet the NERC Reliability Standards.

9. Why can't local generation such as roof top solar replace replace the local area generation?

Solar energy is a non-dispatchable, intermittent resource whose location is not determined by system needs. This energy cannot serve as a replacement for existing generation for the following reasons:

- *Solar energy is non-dispatchable meaning the output can't be controlled. Therefore, output cannot be increased if the required energy increases and can only be reduced during an oversupply condition by shutting it off.*
- *Solar energy is intermittent meaning the output is influenced by weather conditions particularly clouds. The output of solar can drop significantly in a very short period potentially placing the system at risk.*
- *For solar to replace even a portion of existing generation, there would need to be hundreds of solar installations located in the exact geographic areas of need.*