YOUR ELECTRIC RATES

Mission: *Deliver clean, affordable, reliable energy and excellent customer service.*

Off System Sales and 2011 Audited Financials
City Council Work Session # 5
April 17, 2012

Agenda

- Decision Points
- Review 2011 Audited Financials
- Off System Sales Overview
  - Nodal Market
  - Fuel Adjustment

Decision Points

- Cash Flow Methodology
- Debt Equity Ratio
- Reserve Policies – Replenishment schedule in Revenue Requirements
- General Fund Transfer Policy
- Energy Efficiency
- Scope of Customer Assistance Program coverage

Response to Prior Council Requests

Revenue Requirements - Cash Flow Return Method

- Annual minimum needs of the Utility - Normalized to exclude non-typical items

Cash Flow Methodology Revenue Requirement Components	Test Year ($ Millions)	Basis for Recovery
Total Operations & Maintenance Expense	$ 824	Continue to provide core services
Debt Service	168	Bond Covenant and Financial Policy Compliance
Capital From Current Revenue	111	Funding within Financial Policy guidelines
General Fund Transfer	105	Financial Policy Requirement
Other net (Non-Rate) Revenue	(94)	Transmission Revenue, Other Revenue
Total Revenue Requirements minus Reserves	$ 1,114	

- **Reserves are added to cover non-typical events**

Cash Flow Methodology Revenue Requirement Components	Test Year ($ Millions)	Basis for Recovery
Additional items:		
Contributions to Decommissioning Reserves	6	Financial Policy Requirement-Fund depleted
Required Contributions to Reserves	25	Financial Policy Requirement-Fund depleted
Total Revenue Requirement	$ 1,145	

2x DSC Compared to Cash Flow Method

Fitch Peer Review Ratings Report – June 2011

Debt Service Coverage:

AA- Rating

Median for AA- Rated Utilities 2.48

Debt Service Coverage Ratio (DSC)	**FY 2009 Actual**	**Test Year**	**Test Year**
		With Reserves	*Without Reserves*
Rate Revenue (Test Year at various levels)	$ 1,033,507,095	$ 1,145,071,163	$ 1,114,978,025
Other Revenue	132,427,698	85,966,153	85,966,153
Sub-Total	$ 1,165,934,794	$ 1,231,037,316	$ 1,200,944,178
Operations & Maintenance	$ 873,237,069	$ 824,736,318	$ 824,736,318
Balance Available for Revenue Debt Service	**$ 292,697,724**	**$ 406,300,999**	**$ 376,207,861**
Revenue Debt Service	$ 176,582,728	$ 167,713,457	$ 167,713,457
Debt Service Coverage (DSC)	**1.66**	**2.42**	**2.24**

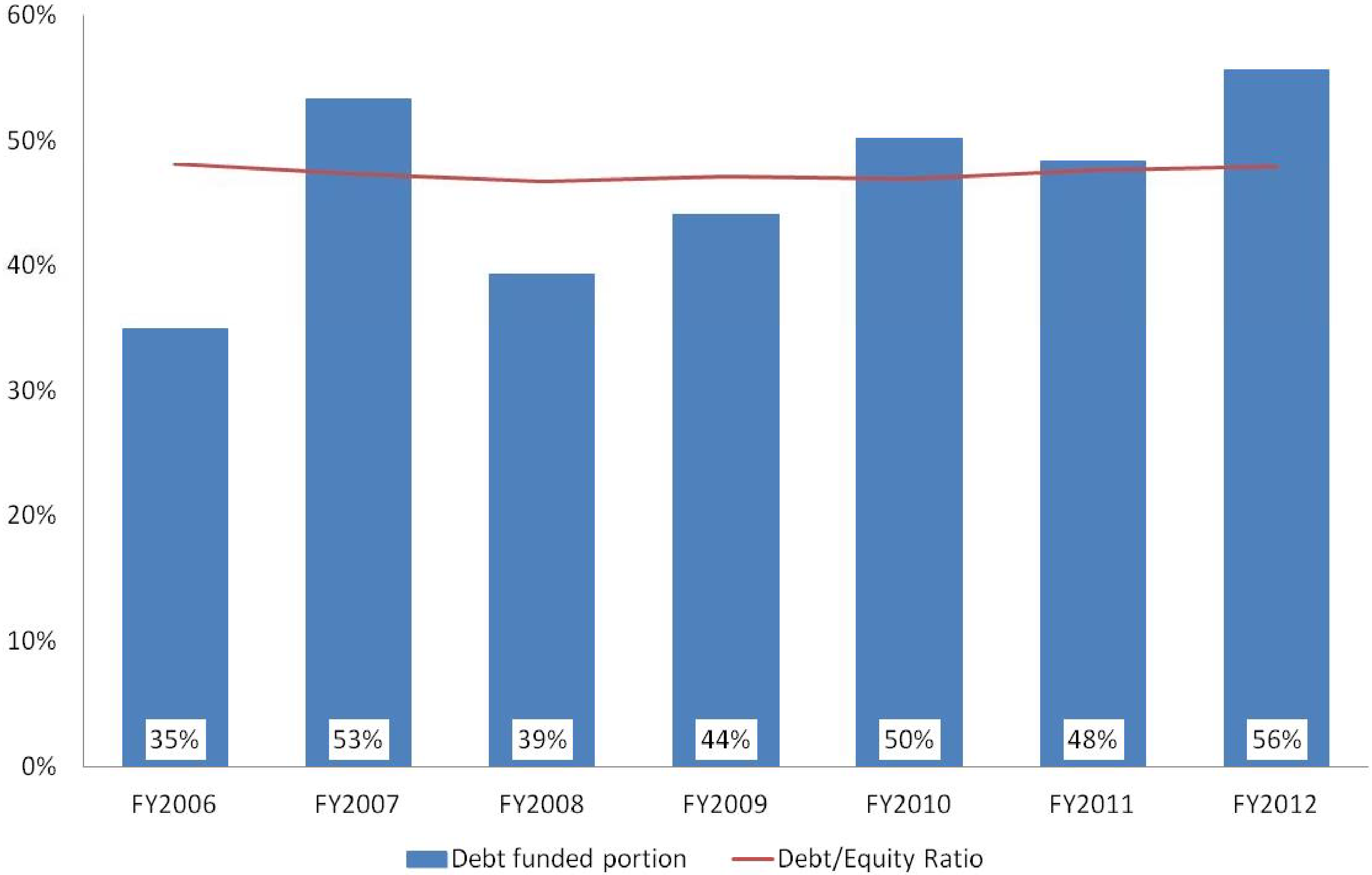
2 Times DSC Method compared to Cash Flow Method

Return Components	Proposed Cash Flow Method	2 Times DSC Method
Debt Service	$168 million	$168 million
General Fund Transfer	$105 million	$105 million
Cash Portion of Construction Projects	$111 million	$63 million
Contributions to Reserves	$31 million	$0
Totals	**$415 million**	**$336 million**

Total Deficiency: $79 Million

Increase Debt Funding of CIP

Debt Funded Portion of Construction (CIP)



Change in Reserve Policies

Managing Cash

Checkbook

Working Capital

45 days of O&M less Fuel

Operating Cash

Savings

for Non-Typical Events

Repair and Replacement Reserve

Strategic Reserve:

- *Emergency*
- *Contingency*
- *Rate Stabilization*

Decommissioning Reserve

Financial Policy Maximums

Savings for Non-Typical Events	Maximum for Non-Typical Events
Repair and Replacement Reserve	½ of Depreciation Expense
Strategic Reserve:	Strategic Reserve:
Emergency	*60 days of O&M less Fuel*
Contingency	*60 days of O&M less Fuel*
Rate Stabilization	*90 days of Power Supply Cost*
Decommissioning Reserve	Power Plant Retirement Cost

Financial Policies for Reserves

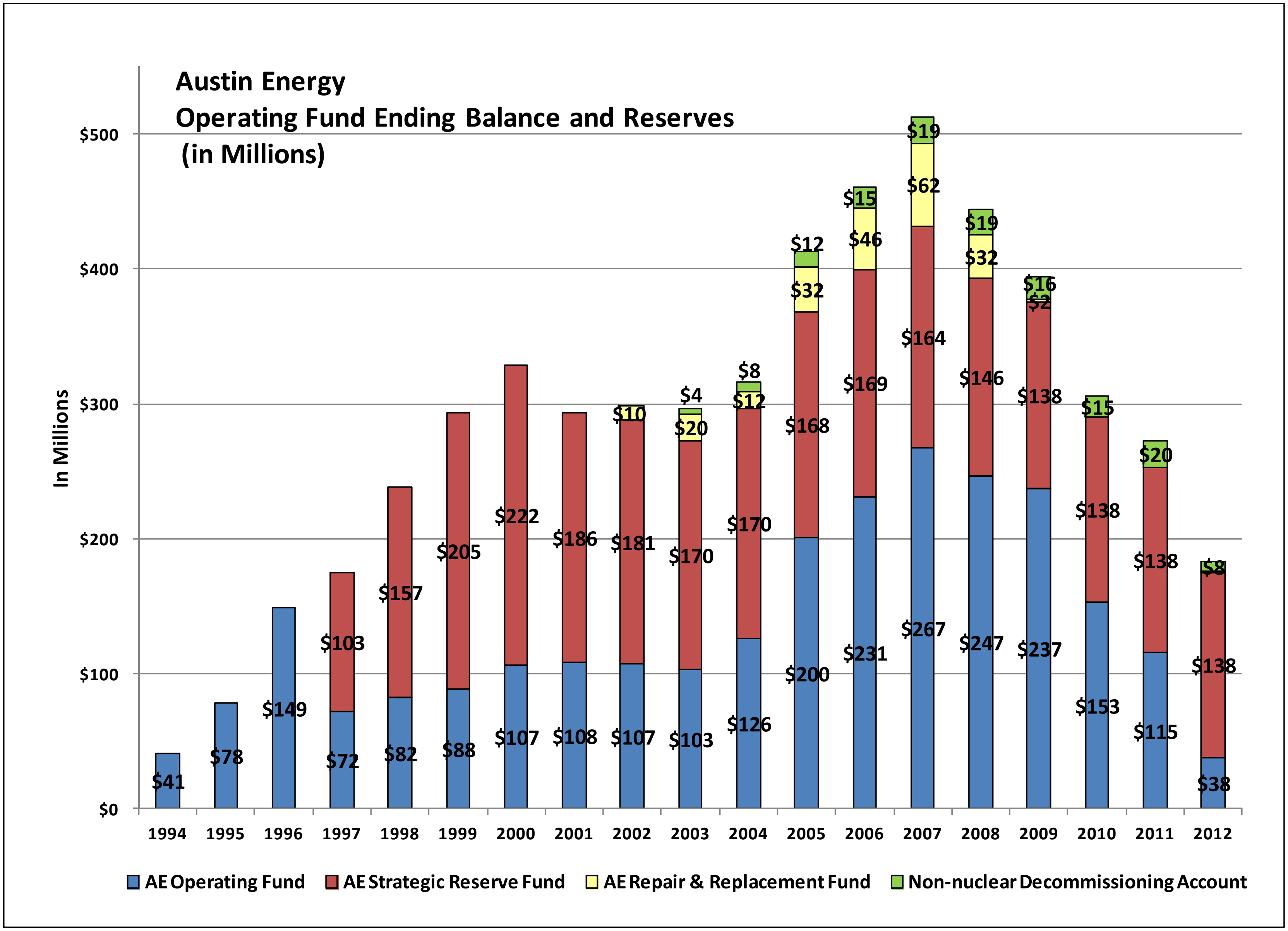
Savings for Non-Typical Events	Current Savings for Non-Typical Events	Maximum for Non-Typical Events
Repair and Replacement Reserve	$ 0	$ 61 million
Strategic Reserve:	Strategic Reserve:	Strategic Reserve:
Emergency	$ 69 million	$ 69 million
Contingency	$ 69 million	$ 69 million
Rate Stabilization	$ 0	$ 98 million
Decommissioning Reserve	$ 0	$56 million

Reserve Replenishment Calculation in Revenue Requirement

- Reserve replenishment in the 2009 Test Year is $75 million:
  - Proposed annual recovery over 3 years = $ 25 million
  - Proposed annual recovery over 5 years = $ 15 million

- Replenishment needs have increased from $75 million in the Test Year to $153 million today due to further depletion of cash in the interim:
  - Current annual recovery over 3 years = $ 51 million
  - Current annual recovery over 5 years = $ 31 million

Operating Fund Ending Balance and Reserves



Rate Stabilization Replenishment Calculation

- Financial Policy Maximum = 90 days of Power Supply Cost
  - 90 days = $98 million
  - 60 days = $65 million
- Reducing the Rate Stabilization maximum from 90 days to 60 days decreases the Revenue Requirements
  - Amortize savings over 3 years = $11 million
  - Amortize savings over 5 years = $ 7 million
- Contributions to Reserves in the Revenue Requirements would be:
  - Annual recovery over 3 years = $ 14 million
  - Annual recovery over 5 years = $ 8 million

Change in General Fund Transfer

General Fund Transfer Calculation

12% transfer rate on non-fuel (3 year average) revenue, with GFT $105M floor until 12% = $105M

- GFT increases reflect true revenue growth
- Improves certainty in forecasts; removes fuel volatility
- Addresses Electric Utility Commission issue on fuel in GFT
- Establishing floor of $105M mitigates impact on General Fund of changing to 12% on non-fuel revenue
- Simplified calculation

2011 Audited Financials Compared to the Test Year

Income Statement

For the year ending September 30 (In Thousands)	2009	2010	2011
Operating Revenues	$ 1,162,286	$ 1,147,676	$ 1,249,139
Operating Expenses	869,247	887,152	932,802
Depreciation	114,172	121,570	132,077
Net Operating Income	$ 178,867	$ 138,954	$ 184,260
Nonoperating & Other Revenue (Expense)	(18,798)	138	7,595
Interest Income	17,402	9,740	9,732
Interest Charges and Other Expense	(86,530)	(80,030)	(81,823)
Net Income before Contributions and Transfers	**$ 90,941**	**$ 68,802**	**$ 119,764**
Contributions	5,956	4,856	10,261
Transfers to General Fund	(95,000)	(101,000)	(103,758)
Net Income (Loss)	**$ 1,897**	**$ (27,342)**	**$ 26,267**

Operation and Maintenance Expenditures

	FY 09 Test Year	FY 11 Preliminary
Power production	$168.23 MM	$163.89 MM
Transmission	$77.82 MM	$78.30 MM
Distribution	$49.04 MM	$46.55 MM
Customer and Information	$45.54 MM	$46.09 MM
General and Administrative	$104.69 MM	$106.49 MM
Total O&M	$445.32 MM	$441.32 MM

- O&M costs excludes recoverable fuel
- FY 2011 O&M Costs was within 0.90 % FY 2009 Test Year
- FY 2011 does not include all Know and Measurable adjustments that would be made if FY 2011 was used as a Test Year

Preliminary Comparison of Revenue Requirements

	FY 09 Test Year	FY 11 Preliminary
Total Operations & Maintenance	$445 MM	$441 MM
Total recoverable fuel	$375 MM	$442 MM
Other Revenue and Expenses	$(90) MM	$(83) MM
Debt Service	$168 MM	$165 MM
General Fund Transfer	$105 MM	$105 MM
Capital From Current Revenue	$111 MM	$99 MM
Required Contributions to Reserves (3 Year Recovery)	$25 MM	$51 MM
Contributions to Decommissioning Reserves (10 Year Recovery)	$6 MM	$6 MM
Total Revenue Requirements	$1,145 MM	$1,226 MM

Notes:

FY 2011 Preliminary numbers do not include Period 13 adjustments

FY 2011 CIP Expenditure reflects one-time project deferrals

FY 2011 does not include all Know and Measurable adjustments that would be made if FY 2011 was used as a Test Year

GFT is based on the FY 2012 budget

Off System Sales

ERCOT Zonal Market – Prior to December 1, 2010

- Balanced schedules were submitted to ERCOT with equal amounts of energy sales obligations and generation resources
- Excess generation, generation greater than load, was sold to other market participants when it was economical to do so and such transactions were recorded as "off-system" sales
- Off-system sales were scheduled as discrete transactions and easy to account for
- Over time, as AE load increased available excess generation decreased and correspondingly the amount of off-system sales decreased

ERCOT Nodal Market – Starting December 1, 2010

- ERCOT forecasts load for the entire system
- Centralized ERCOT Generation Dispatch
  - Balanced schedules no longer submitted to ERCOT
  - Offer all generation to ERCOT for centralized dispatch
  - ERCOT dispatches all available generation from least cost to most expensive to meet the ERCOT load forecast
- Austin Energy generation serves the ERCOT system load
  - No longer matching of AE generation with AE customer load
    - AE generation in any 5 minute interval may be more or less than AE customer load
  - Traditional Concept of Excess Generation (off-system sales) no longer exists in the ERCOT system

Summary

- Traditional concept of off-system sales no longer applies in the nodal market
  - Austin Energy no longer balances its own customer load and generation
  - Generation serves the ERCOT market
  - Energy is purchased through ERCOT
  - Energy is sold through ERCOT
- Overall AE is a net buyer of energy, not a net seller
- Value to AE and customers is the Net ERCOT Settlement (i.e., net ERCOT sales revenue)
  - Benefit of generation ownership and sales flows back to customers through fuel charge

ERCOT Market Changes Driving Fuel Policy Recommendation

All ERCOT sales revenue directed to customers through the fuel charge

- Test Year Adjustments to 2009 Off System Sales:

  Test Year Normalization of Load & Resources (Off-system sales):

  – Step 1: Remove off-system sales revenue and related off-system fuel expense from test year *($44 million)*

  – Step 2: Model test year load requirements needed to serve customers and AE fuel costs for owned generation

  – Step 3: Adjust test year with the simulated results (replacing off-system sales revenue and associated fuel costs) *($66 million)*

Questions