Northwest **Power** and
Conservation Council

September 6, 2017

MEMORANDUM

TO: **Power Committee**

FROM: **Charlie Grist**

SUBJECT: **Briefing on Bonneville rate structures and conservation program mechanisms**

BACKGROUND:

Presenters: Emily Traetow – Public Utility Specialist and Kim Thompson – Acting Vice President of Energy Efficiency

Summary: Bonneville will brief the Power Committee on the overall structure of Bonneville's power and transmission customers, contracts, and rates. Emily Traetow will describe Bonneville's overall revenue requirement and the characteristics of its utility customers. The briefing will address how Bonneville recovers required revenues thru the sale of a suite of power and transmission products and will touch on the flow of both costs and benefits of energy efficiency.

Kim Thompson will brief the committee on the design and structure of Bonneville's conservation programs and its related wholesale rate structures. Ms. Thompson will address the current structure of Bonneville's Energy Efficiency Incentive (EEI) program which began operating October 2011 and will illustrate key elements of the EEI program and how utility customers are using it. She will describe how Bonneville and its customers arrived at the current conservation implementation model, and explain recent issues and challenges.

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Relevance: This is a follow-up to questions raised at the August power committee meeting. The briefing will provide a broad understanding of how Bonneville implements its conservation commitments. It will also provide context for the proposed Value of Conservation white paper which will focus on how revenue requirements are impacted by energy efficiency development and how the impacts flow back through utilities to ultimate consumers.

Workplan: Item A.1. Implement the Seventh Power Plan and related Council priorities

B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

BPA's EE Funding Model

A description of how BPA funds efficiency and how we got here

A History Of Efficiency Funding

Where We Came From

Before 2012

EE funding blended equity and utility control with utility opportunity

CRC: Conservation Rate Credit, allocated based on utility size. Optional and much smaller (roughly 1/3 the size) than today's Energy Efficiency Incentive funding.

CAA: Conservation Acquisition Augmentation: Funds allocated on utility request based on individual utility opportunity and need.

BPA Direct Acquisition: Programs like Energy Smart Grocer worked directly with end users to acquire efficiency outside of utility programs.

A Case for Change

BPA’s Regional Dialog Policy and Tiered Rates Methodology raised questions about BPA’s EE program design.

Customer Concerns

Local Control: Utilities wanted to ensure they were directly in control of the work going on in their service territory

Equity: Utilities wanted to ensure their members’ rates were not subsidizing other utilities

Choice in implementation: Utilities wanted to pick the right measures for their retail consumers

The Post 2011 Process

The Foundation of BPA's Current EE Model

Post 2011 Process Principles

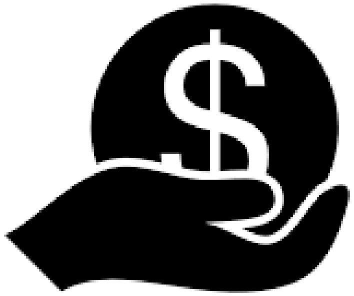
- ✓ Develop public power's share of all cost-effective conservation consistent with the NW Power Act.
- ✓ Provide services that maximize regional economies of scale, market influence and local assistance opportunities.
- ✓ Leverage resources to maximize existing infrastructure and avoid duplication of effort across the region.
- ✓ Ensure consistency with the principles of tiered rates.
- ✓ Provide choices to be responsive to the diversity of needs across the region.
- ✓ The bulk of conservation is best managed at the local level.
- ✓ Balance increased flexibility with cost.
- ✓ Manage risk associated with change.
- ✓ Support long-term high customer satisfaction.
- ✓ Advance energy efficiency in the Pacific Northwest.

Post 2011 Outcome

Funding Equity

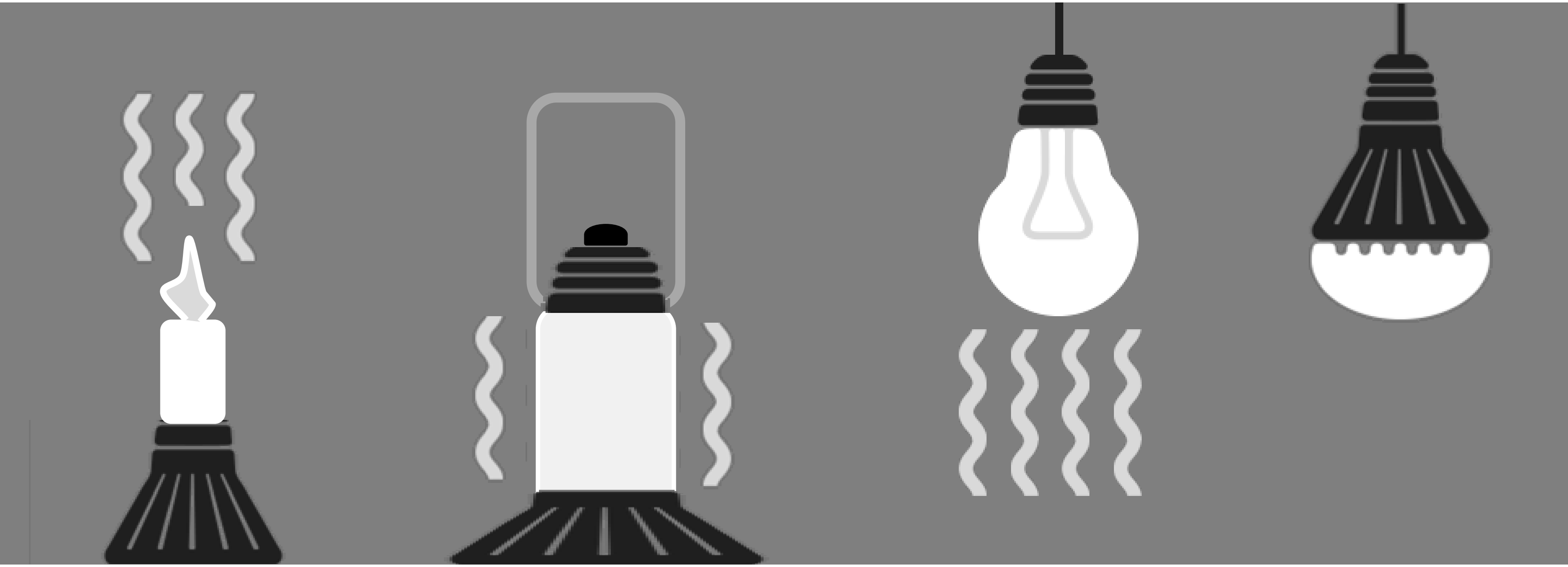
Regional Infrastructure

Collective Targets



Utility Self-Funding

Evolution over Time



Post 2011 Review

Planned assessment, conducted after one rate period of implementation. Results:

- Reaffirmed:
  - Equity model for Energy Efficiency Incentive (EEI)
  - Self-funding expectation (25%)
- Established:
  - Rate period rollover (initially 5%)
  - A one-year Implementation Manual (IM)
  - A formal and collaborative process for regional program development
  - Conservation Billing Credits*
  - Established Low Income Working Group

* Rendered redundant by later move to Expense funding

2015 IPR-2

Customers requested BPA to consider eliminating capitalized Energy Efficiency investments, shifting to expense funding.

BPA enacted this shift as part of 2015's Integrated Program Review.

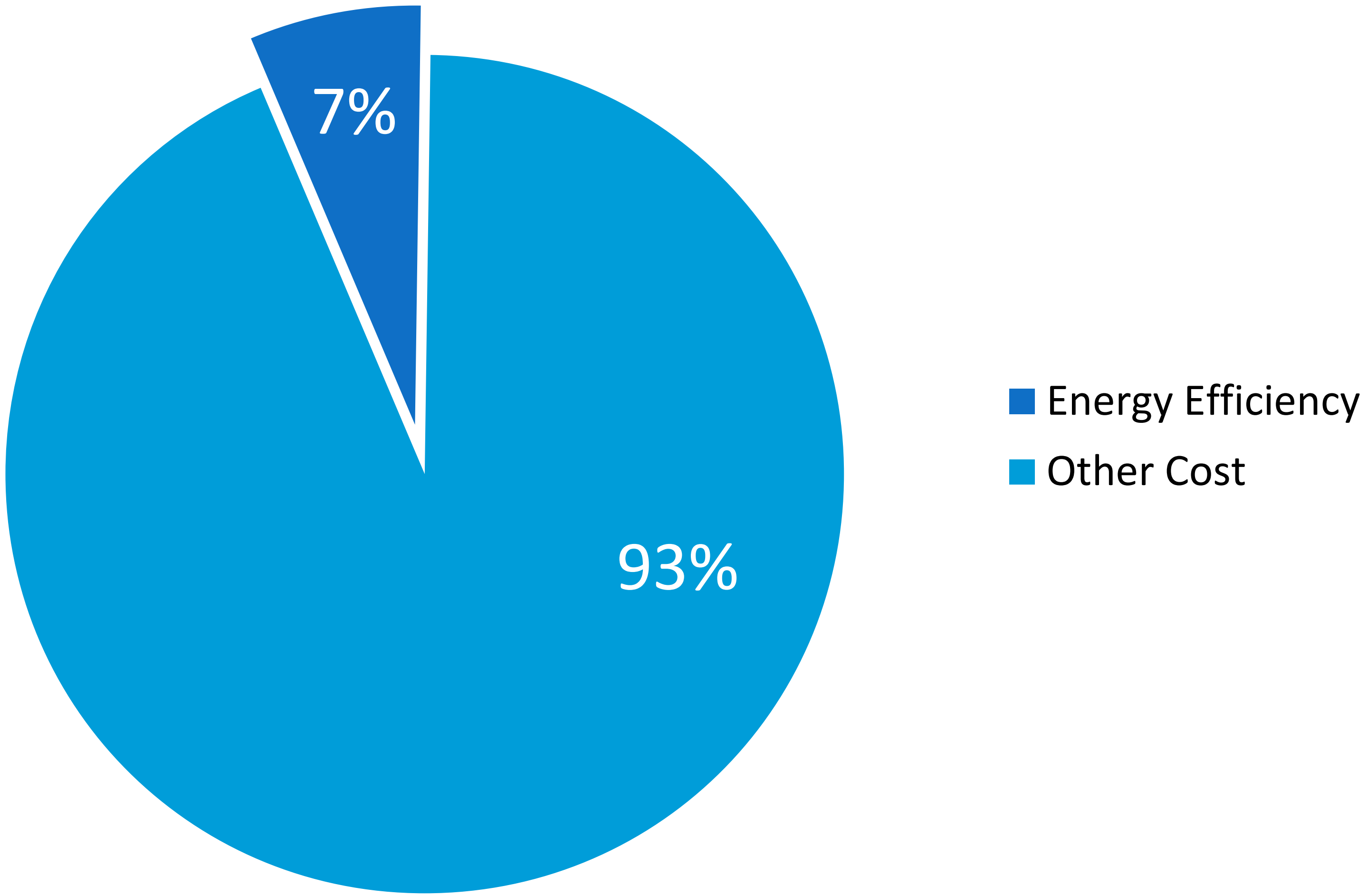
Focus 2028

Focusing on overall competitiveness, BPA engaged on a number of agency issues including energy efficiency. Results:

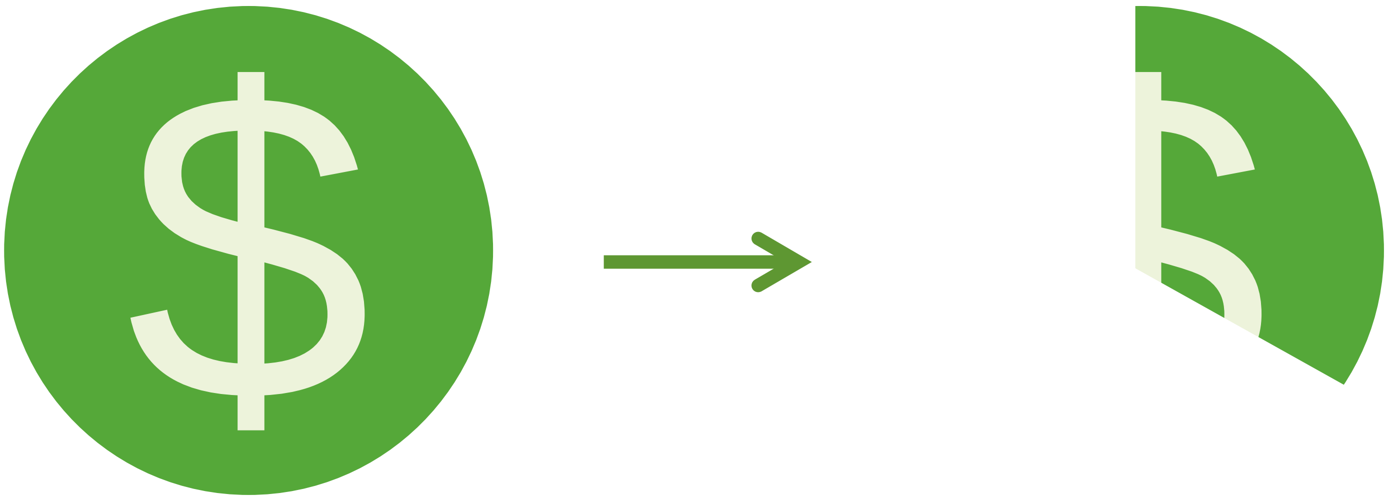
- Reaffirmed equity model for EEI
- Aligned IM publication to rate periods
- Increased self-funding expectation (30%)
- Streamlined bilateral transfers
- Increased rate period roll over
- Began process to reassess BPA's energy efficiency goal

The Nuts and Bolts

Efficiency in BPA's Tier One Rates



How utilities describe BPA’s funding

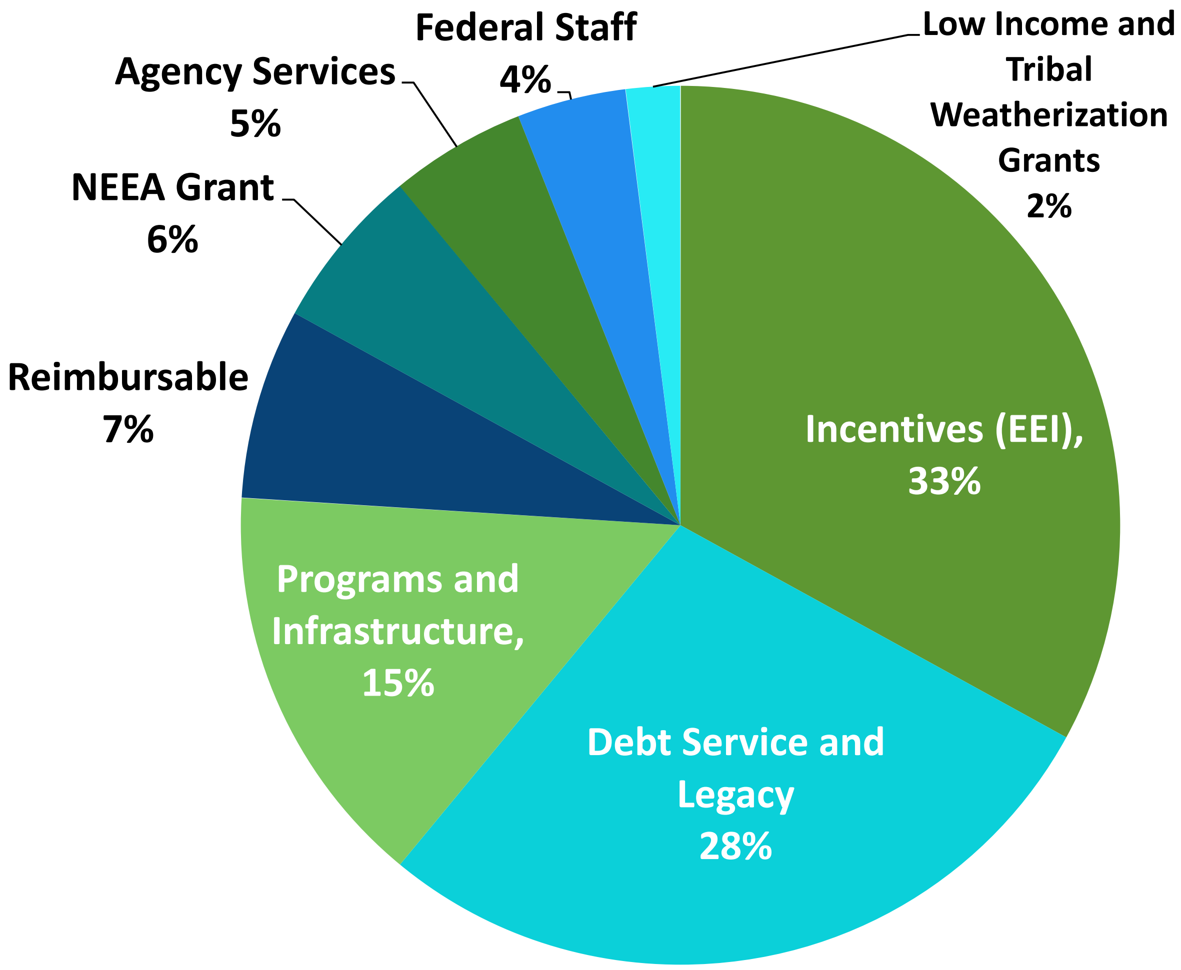


RATES
IN

EEI
OUT

Components of EE Cost

Breaking down the 7%

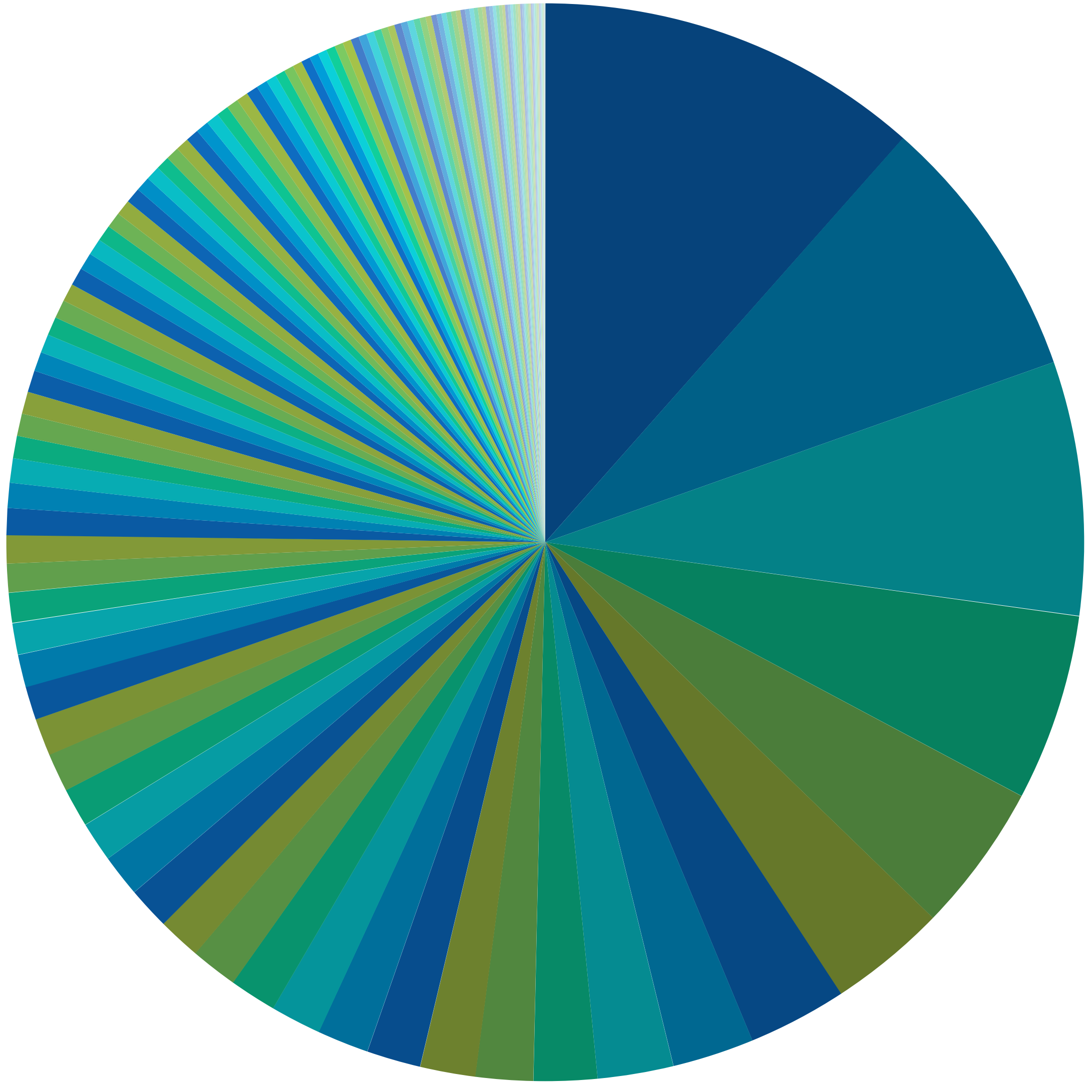


Based on FY16-17 Rate Period

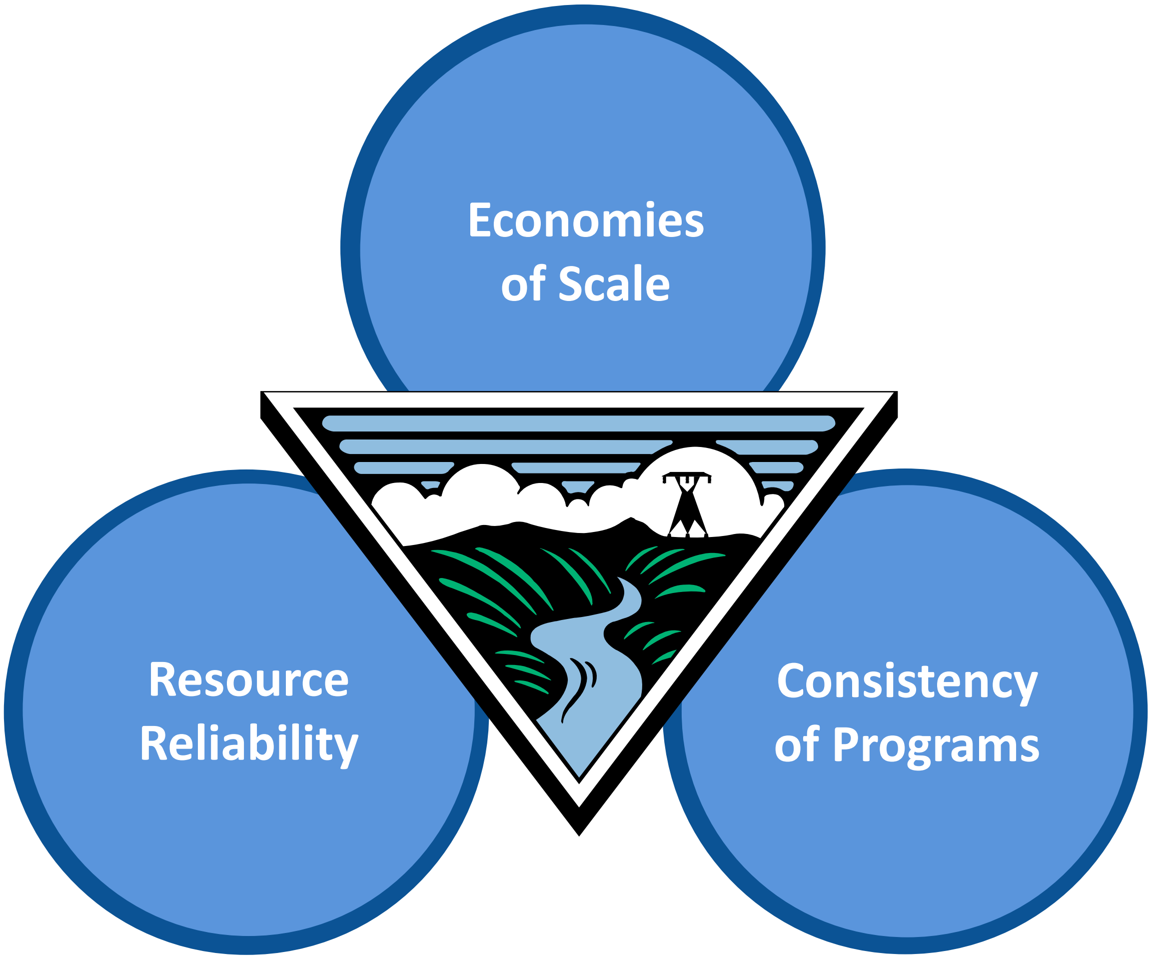
Allocation of Incentives

Breaking Down the 33%

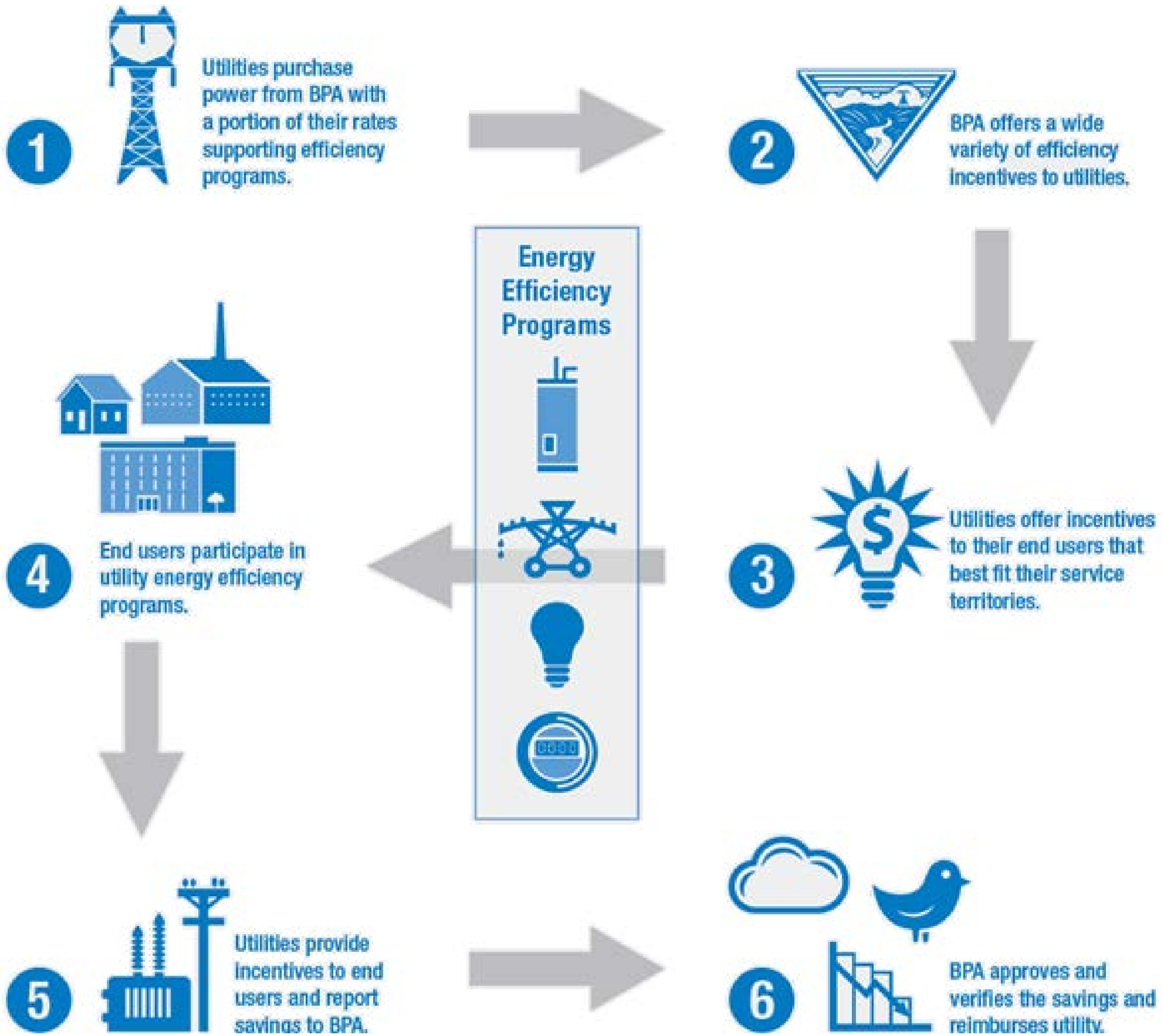
Incentive budgets are based on each customer's Tier One Cost Allocator



Other BPA Program Elements



How Incentives are Deployed



Incentive Funding Flexibility

Flexibility

- Bilateral transfers to move funds at the request of customers
- Carry over unspent funds at the end of the rate period (10% or $50,000)
- Distribute funds through the Unassigned Account

Limitations

- Move unspent funds from one customer to another
- Carry over more than the customer cap

Has it Worked?

Energy Efficiency Funds Spent By Customers

Rate Period	Budget	Actuals	% Spent
FY 12/13	$126,552,591	$125,531,924	99%
FY 14/15	$137,150,839	$135,972,588	99%

Dollars Transferred through Bilateral Transfers

Rate Period	Total Transferred Between Customers
FY 12/13	$5,535,045.00
FY 14/15	$7,179,967.02
FY 16/17 (through Aug)	$6,489,675.53

Customers that Transferred Funds

Rate Period	Unique Utilities Transferring Funds
2012-2013	61
2014-2015	74
2016-2017	48

Questions?

Bonneville Power Administration Power Sales Contracts and Rate Structure

Council Meeting, Power Committee – Spokane

September 12, 2017

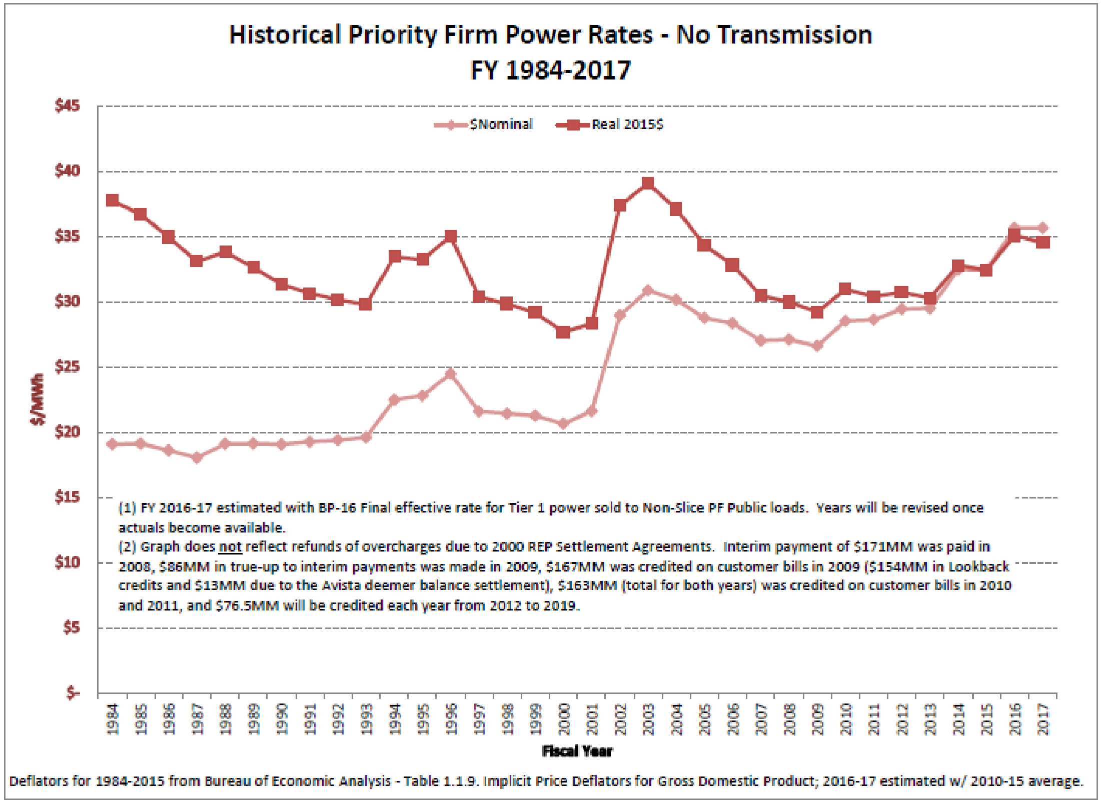
NW Power Act: Sale of Power

- Section 5 of the NW Power Act states that BPA must serve net requirement of PNW customer, if requested
  - Net requirement is equal to a customer's load less its "dedicated" resources
  - Preference customers and investor-owned utilities may request "requirements service" from BPA
  - Such net requirement sales shall be at rates established pursuant to section 7 of the Act (PF rates for preference customers, NR rates for IOUs)
- Regional Dialogue Contracts offered in 2008 (expire in 2028) implement BPA's net requirement obligation
  - Three core contract types: Load Following, Block, and Slice/Block

Contract Type	Customer Count	FY2018 Net Requirement Load (aMW)*
Load Following	118	3,224
Block-only	2	511
Slice/Block	14	3,055
Slice Share		*1,597*
Block Share		*1,458*
Total	**134**	**6,790**

*Forecasts from BP-18 Final Proposal

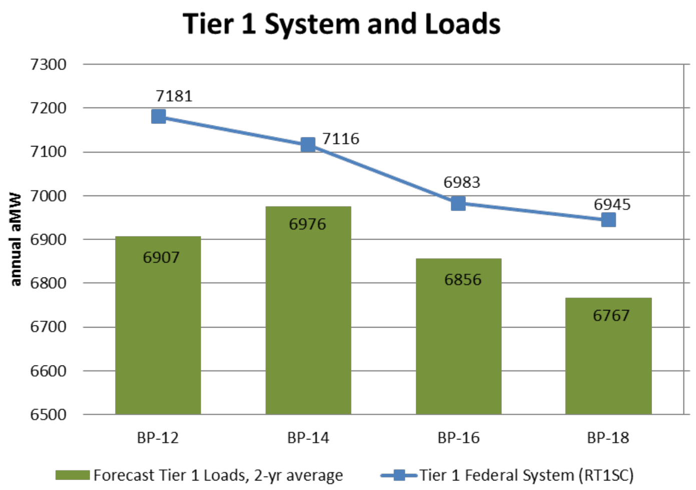
NW Power Act: Rates



- Section 7 of the NW Power Act states BPA must set its rates to recover its costs with specific guidance on:
  - Allocation of resource costs
  - Allocation of Residential Exchange costs
  - Determining rates for DSIs
  - A public rates process
  - FERC oversight
- NW Power Act grants BPA discretion on other ratemaking issues (like rate design)
  - Tiered Rate Methodology (TRM) implements Regional Dialogue policies and locks down PF rate design.
  - Rate are currently established in rate cases every two years.

Regional Dialogue and TRM Basics

- Tiered PF Rates
  - Establishes a two-tiered PF rate design applicable to net requirements power for Publics
  - Determines the amount of power a customer is eligible to purchase at Tier 1 rates by establishing a Rate Period High Water Mark (RHWM) for each customer that is the dividing line between Tier 1 rates and Tier 2 rates or non-Federal resources.
  - A customer cannot buy more power that its net requirement, regardless of its RHWM.
- Cost Differentiation
  - Differentiates between the costs of service associated with existing Tier 1 System Capability (Tier 1 Rates) and the incremental costs of power needed to serve any portion of a Public's annual net requirement not served at a Tier 1 Rate (i.e. Tier 2 Rates).
- Allows customer to choose between buying from BPA at a Tier 2 rate and purchasing from other sources of power
  - Sends marginal price signals to the bulk of BPA's customers
  - Promotes energy efficiency and resource development



Power Rates - Tiered Rate Design

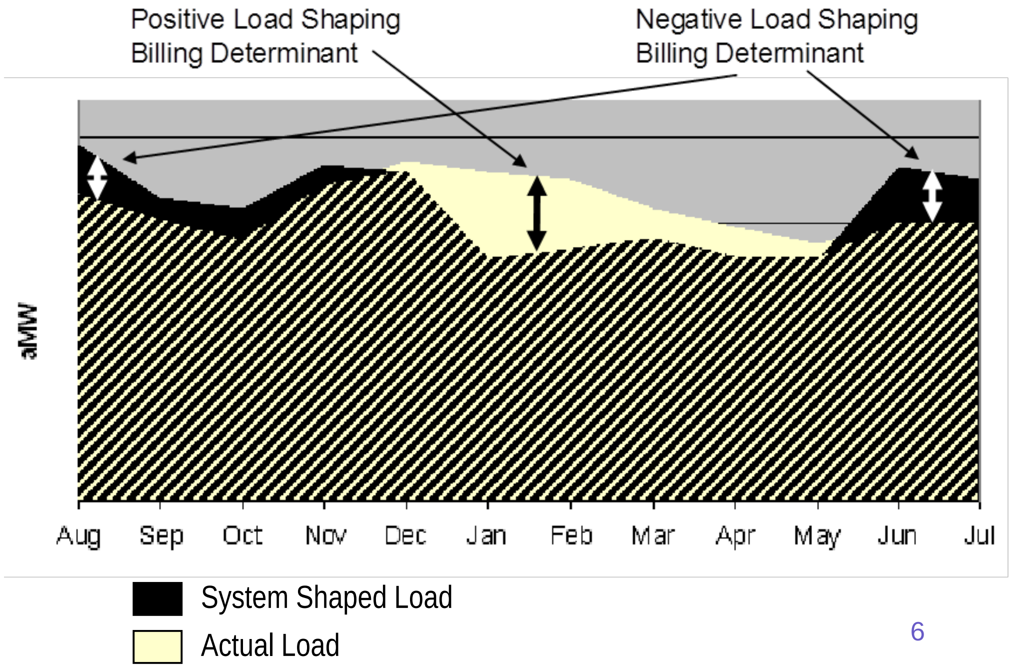
$$TOCA = \frac{\min[RHWM, Netreq]}{\sum RHWM}$$

- Tier 1 Customer Charges
  - Composite Charge
    - All customers pay a percentage of revenue requirement (similar to Slice)
    - Collects the majority of the Tier 1 Revenue Requirement and is applicable for all customers. Billed based on customer's Tier 1 Cost Allocation (TOCA).
  - Slice Charge (e.g. slice implementation)
    - Collects costs or returns credits specific to the Slice product (has been $0 since FY2012). Billed based on customer's Slice percentage.
  - Non-Slice Charge (e.g., surplus sale revenue, credit risk, etc.)
    - Collects costs or returns credits specific to non-Slice products (likely a net credit).
    - Billed based on a customer's non-Slice TOCA

Power Rates - Tiered Rate Design

- Tier 1 Demand Charge
  - Charges for demand use above monthly average HLH energy take. However, each customer has a certain grandfathered amount of their demand above average (contract demand quantity or CDQ).
  - Rate is based on the fixed capital cost of the most economic capacity machine.
- Tier 1 Load Shaping Charge
  - Compares a customer's load to the Tier 1 System Capability and charges or credits based on buys and sells at a posted forecast market price (Load Shaping rates).
- Tier 2 Charge
  - Based on the cost of providing a flat annual block of power at the marginal cost of new BPA power purchases and resource acquisitions. Also includes BPA overhead costs, risk-related costs, transmission, etc.

T1 Load Shaping Charge



Transmission Rates

- Network Rates
  - Open Access Tariff rates: Point-to-Point and Network Transmission
  - Grandfathered rates: Formula Power Transmission (pre-1984) and Integration of Resources (1984-1996)
  - Based on Network costs and usage
- Intertie Rates
  - Southern Intertie: for use of AC and DC ties with California
  - Montana Intertie and Eastern Intertie: for use of tie with Montana
- Utility Delivery Rate
  - For use of federal facilities delivering power to utilities at low voltages
- Ancillary Services and Control Area Services Rates
  - For support services used in transmission of power on BPA lines, such as regulation, frequency, reactive and voltage support and support for the integration of resources

Contract Type	Customer Count	NT Contract Count
Load Following	118	118
Block-only	2	0
Slice/Block	14	7
Total	**134**	**125**

*Forecasts from BP-18 Final Proposal

Conservation in Power Rates

- PF conservation costs (including EEI) are in the Composite Customer Charge, a Tier 1 rate.
  - All PF customers, regardless of contract type, pay their share of conservation costs using their TOCA (based on the lesser of their net requirement load or RHWM).
- How a customer’s BPA purchase obligation and charges are impacted by conservation varies by customer due to contract type and timing of the conservation.
  - Slice/Block and Block customers’ purchase obligations and charges are based on forecasts; therefore, conservation only reduces a customers charges to BPA if it occurs prior to the annual net requirement process.
  - Load Following customers purchase their actual load amounts from BPA; therefore, conservation reduces energy charges to BPA regardless of when it occurs. But the timing of the conservation can impact whether or not the customer pays Tier 1 or Tier 2 rates for its load.
  - See following examples for impacts to BPA energy charges.

Example 1: Block Customer

USING BP18 Rate Case Data	TRL aMW	NLSL aMW	Existing Resource aMW	TRL - NLSL - Existing Resource aMW	RHWM aMW	Above-RHWM Load aMW	Net Requirement aMW	Tier 1 Block Amounts aMW	
Seattle City Light, forecast	1126.595	0.000	615.746	510.849	515.503	0.000	510.849	510.849	
Seattle City Light, 5% conservation before annual Net Requirements	1070.265	0.000	615.746	454.519	515.503	0.000	454.519	454.519	
Seattle City Light 5% conservation after annual Net Requirements	1126.595	0.000	615.746	510.849	515.503	0.000	510.849	510.849	can market surplus generation
	TOCA	Slice%	Non-Slice TOCA	Composite Charge	Non-Slice Charge	Slice Charge	Load Shaping Charge	Total Power Charges	Effective Rate $/MWh
Seattle City Light, forecast	0.0735580	-	0.0735580	$187,406,244	-$26,428,356	$0	$9,356,380	$170,334,268	$38.06
Seattle City Light, 5% conservation before annual Net Requirements	0.0654470	-	0.0654470	$166,741,572	-$23,514,192	$0	$8,327,093	$151,554,473	$38.06
Seattle City Light 5% conservation after annual Net Requirements	0.0735580	-	0.0735580	$187,406,244	-$26,428,356	$0	$9,356,380	$170,334,268	$38.06

*Not the customer’s actual charges, based on forecasts in rate case. Does not include REP Refund, Low Density Discount, and Irrigation Rate Discounts.

Example 2: Slice/Block Customer

USING BP18 Rate Case Data	TRL aMW	NLSL aMW	Existing Resource aMW	TRL - NLSL - Existing Resource aMW	RHWM aMW	Above-RHWM Load aMW	Net Requirement aMW	Tier 1 Block + Critical Slice Amounts aMW	
Okanogan PUD, forecast	73.986	0.000	24.258	49.728	45.174	4.554	45.174	45.174	
Okanogan PUD, 5% conservation before annual Net Requirements	70.287	0.000	24.258	46.029	45.174	0.855	45.174	45.174	
Okanogan PUD, 5% conservation after annual Net Requirements	73.986	0.000	24.258	49.728	45.174	4.554	45.174	45.174	can market surplus generation
	TOCA	Slice%	Non-Slice TOCA	Composite Charge	Non-Slice Charge	Slice Charge	Load Shaping Charge	Total Power Charges	Effective Rate $/MWh
Okanogan PUD, forecast	0.0065047	0.0036117	0.0028930	$16,572,252	-$1,039,416	$0	$97,984	$15,630,820	$39.50
Okanogan PUD, 5% conservation before annual Net Requirements	0.0065047	0.0036117	0.0028930	$16,572,252	-$1,039,416	$0	$97,984	$15,630,820	$39.50
Okanogan PUD, 5% conservation after annual Net Requirements	0.0065047	0.0036117	0.0028930	$16,572,252	-$1,039,416	$0	$97,984	$15,630,820	$39.50

*Not the customer’s actual charges, based on forecasts in rate case. Does not include REP Refund, Low Density Discount, and Irrigation Rate Discounts.

Example 3: Load Following Customer

USING BP18 Rate Case Data	TRL aMW	NLSL aMW	Existing Resource aMW	TRL - NLSL - Existing Resource aMW	RHWM aMW	Above-RHWM Load aMW	Tier 2 Amount aMW	actual Tier 1 Load aMW	actual Net Requirement Load aMW
Kootenai Elec Coop, forecast	53.233	0.000	0.000	53.233	50.181	3.052	3.052	50.181	53.233
Kootenai Elec Coop, 5% conservation before RHWM Process	50.571	0.000	0.000	50.571	50.181	0.390	0.390	50.181	50.571
Kootenai Elec Coop, 5% conservation after RHWM Process	53.233	0.000	0.000	53.233	50.181	3.052	3.052	47.519	50.571
	TOCA	Non-Slice TOCA	Composite Charge	Non-Slice Charge	Load Shaping Charge	Demand Charge	Tier 2 Charge	Total Power Charges	Effective Rate $/MWh
Kootenai Elec Coop, forecast	0.0072256	0.0072256	$18,408,912	-$2,596,056	$285,285	$751,330	$727,103	$17,576,574	$37.69
Kootenai Elec Coop, 5% conservation before RHWM Process	0.0072256	0.0072256	$18,408,912	-$2,596,056	$363,875	$751,357	$0	$16,928,088	$38.21
Kootenai Elec Coop, 5% conservation after RHWM Process	0.0072256	0.0072256	$18,408,912	-$2,596,056	-$250,559	$751,357	$727,103	$17,040,757	$38.47

*Analysis assumes conservation load reduction occurs as a flat block. Not the customer's actual charges, based on forecasts in rate case. Does not include REP Refund, Low Density Discount, and Irrigation Rate Discounts.