Public Rate Design Methodology (PRDM)

Workshop #3

Chapter 5, Tier 1 Rate Design

Meeting 9 a.m. – 4 p.m.

February 21, 2024

RATE METHODOLOGY POST 2028

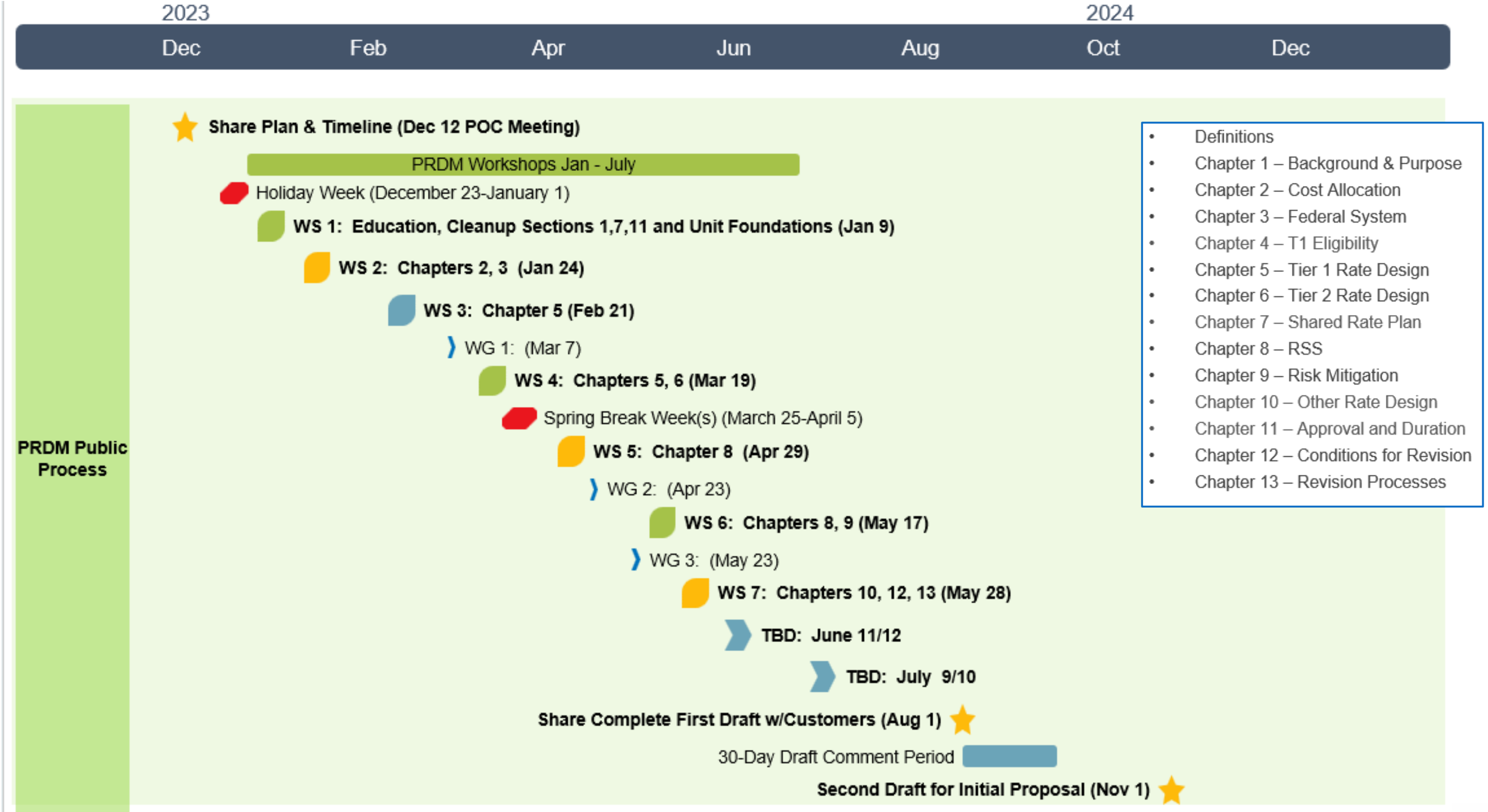
Agenda

Time Start	Time End	Topic	Presenter(s)
9 a.m.	9:10	Welcome, Introduction, Agenda, and Housekeeping	Scott Reed, Policy Lead
9:10	9:30	Chapter 5: Orientation	Scott Reed
9:30	10:30	Chapter 5: Tier 1 Rate Design Background	Garth Beavon, Rates Economist
10:30	10:40	BREAK	
10:40	12:00	Chapter 5: Continued and Possible Changes	Garth Beavon
12:00	1:00	LUNCH BREAK	
1:00	1:45	TOCA to $/MW Proof	Garth Beavon
1:45	2:00	BREAK	
2:00	3:00	Rate Design Scenarios	Peter Stiffler, Rates Economist Scott
3:00	3:30	Conclusion & Next Steps	Scott Reed
Note: times are approximate			

Housekeeping

- Connectivity across projects
  - PRDM and planned product design and timing:
    - Our vision is that the core rate design methodology is agnostic to product design and should not preclude any particular design – at least that's where we see things going right now. If you see specific areas in rate design that suggest otherwise, let's talk about those specifics.
      - One exception might be products and services that interact with actual market conditions – see below.
    - Timeline, although our Workshops are only scheduled out right now through the end of May that does not mean the work, nor our customer engagement, terminates at that time. Work is expected to continue into the summer.
  - PRDM and new markets:
    - We've flagged this as an area we may need to leave room for future 7(i) Processes to resolve. For example, we could purposefully carve out areas of the PRDM to be altered or populated for finalization in the BP-29 rate case process.
- Timeline updates
- Parking lot
- Redlines

Timeline


2023
2024
Dec
Feb
Apr
Jun
Aug
Oct
Dec
PRDM Public Process
Share Plan & Timeline (Dec 12 POC Meeting)
PRDM Workshops Jan - July
Holiday Week (December 23-January 1)
WS 1: Education, Cleanup Sections 1,7,11 and Unit Foundations (Jan 9)
WS 2: Chapters 2, 3 (Jan 24)
WS 3: Chapter 5 (Feb 21)
WG 1: (Mar 7)
WS 4: Chapters 5, 6 (Mar 19)
Spring Break Week(s) (March 25-April 5)
WS 5: Chapter 8 (Apr 29)
WG 2: (Apr 23)
WS 6: Chapters 8, 9 (May 17)
WG 3: (May 23)
WS 7: Chapters 10, 12, 13 (May 28)
TBD: June 11/12
TBD: July 9/10
Share Complete First Draft w/Customers (Aug 1)
30-Day Draft Comment Period
Second Draft for Initial Proposal (Nov 1)
Definitions
Chapter 1 – Background & Purpose
Chapter 2 – Cost Allocation
Chapter 3 – Federal System
Chapter 4 – T1 Eligibility
Chapter 5 – Tier 1 Rate Design
Chapter 6 – Tier 2 Rate Design
Chapter 7 – Shared Rate Plan
Chapter 8 – RSS
Chapter 9 – Risk Mitigation
Chapter 10 – Other Rate Design
Chapter 11 – Approval and Duration
Chapter 12 – Conditions for Revision
Chapter 13 – Revision Processes

Parking Lot

Issue	Action	Note
Environmental Attributes T1, T2	New section in Chapter 2	
WRAP and PRM-Related Services	Contract negotiations and Chapter 5 through Peak Load Variance Charge	
Battery Treatment	Contract negotiations, maybe PRDM, likely future 7(i) Process	
Risk framework (e.g., RDC & Secondary energy credits)	Chapter 2, Chapter 9, or potential future 7(i) Process	
Designated System Obligations	Chapter 3	
Vintage Tier 2 not flat block	Contract negotiations and potential PRDM	
Resource Acquisition Strategy and Execution	Resource Program and Operations	
New Resources Rate Design	Contract negotiations and applicable 7(i) Process	

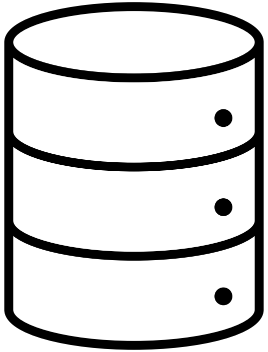
Orienting Chapter 5

- This chapter establishes how the costs associated with Tier 1 will be collected based on some general principles and objectives

- Guiding this design are tradeoffs when considering:
  - Preserving value associated with Tier 1 – specifically as it relates to the use of capacity.
  - Sending economically appropriate price signals
    - Encouraging efficient use of energy and capacity
    - Encouraging efficient non-federal resource development
    - Supporting equitable allocation of costs
  - Promoting equity across range of customer interests
  - Retaining durability over time
  - Balancing simplicity with complexity to support cost causation principles without being too difficult to understand or implement.

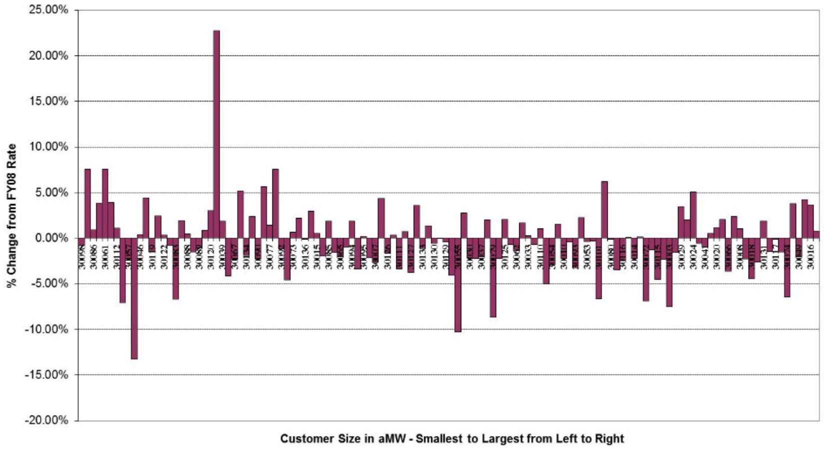
- Why change now?
  - We've all learned a lot through the administration of the TRM over the past decade.
  - The landscape in the utility industry and public power has evolved (and is expected to continue to evolve in the future.)

Simple View of Chapter 5



- This barrel could represent the planned costs associate with T1, which is a fixed amount. We need it full, and we can't overfill.
- The task becomes how to collect those costs and why – evaluating a single factor's impact (e.g., demand) on the overall composition of the barrel (total revenue collection).
- If we collect more based on one factor, another will be reduced so we don't overfill.
- Similarly, if one factor is reduced others much increase.
- Applying pure-market signals to all factors won't work for our task – we have to select which factors scale and adjust to balance the factors that move with the everchanging market.
- Changing one factor of the barrel will have a disparate impact on customers given each customer has different power needs.
- Design is based on balancing the considerations that acknowledge the trade-offs and maintain consistency with ratemaking principles.

Rate Design



Approach:

- Start with fundamentals
- Weigh rate design options for those fundamentals
- Develop a menu of reasonable approaches
- Weigh tradeoffs and impacts to different customer classes
- Negotiate to a preferred theoretical design
- Mitigate as needed – in a straightforward fashion

- Note: single largest driver to select final rate design will likely be expected individual customer rate impacts at the start of the new contract.

Chapter 5:

Tier 1 Rate Design

Garth Beavon, Rates Economist

RATE METHODOLOGY POST 2028

Tier 1 Rate Design Under TRM – (Background Education)

The Tiered Rates Methodology introduced a Priority Firm Tier 1 Rate Design that consisted of three elements, referred to as "Core Charges," that generate revenue for the Tier 1 Cost Pool:

- **Customer Charges**
  - Composite Customer Charge (Recovers costs for which all Tier 1 products pay)
  - Slice Customer Charge (Recovers cost which are unique to the Slice product)
  - Non-Slice Customer Charge (Recovers costs and allocates credits attributable to non-Slice products.)

- **Load Shaping Charge** (Collects revenues necessary for balancing from the Federal generation system shape to the actual seasonal shape of customer loads)

- **Demand Charge** (Charges for capacity needed for meeting customers' monthly peak demand)

Composite Customer Charge

This charge collects the majority of the Tier 1 Revenue Requirement as a starting point to Bonneville's cost recovery. Each customer pays a proportionate share of the Composite Cost Pool. This charge is applicable to all core power products: Slice/Block, Block, and Load Following Service.

In simple terms, a customer's billing determinant is that customer's contract percentage of the Tier 1 System Cost (called the Tier 1 Cost Allocator or "TOCA".) The rate is the dollar value of an approximately 1/100 portion of the costs allocated to the Composite Cost Pool. In BP-24, the total forecast revenue generated from the Composite Customer Charges is approximately $2.5 Billion each year.

Rate	"$2,075,946 per Percentage Point of Billing Determinant per Month." (In BP-24)
Billing Determinant	Customer's Tier 1 Cost Allocator ("TOCA") - This is each customer's contract percentage of the Tier 1 system cost. - The sum of all the TOCA billing determinants with a fully subscribed system is 100%.
Monthly Rate Difference?	No. This Customer Charge is flat (It does not take the shape of monthly market relatives.)
Cost Pool	Composite Cost Pool recovery
Applicable Products	All PF Public products. Load Following, Block, Slice.
Example	A customer has a 10.639 aMW contract eligibility to Tier 1 Power. The sum of all customers is 7107.419 aMW. The TOCA is 0.1497%. The monthly charge is $310,746.

Composite Customer Charge (cont.)

- Discussion. Bonneville's Composite Customer Charge is *not* a traditional "Customer Charge." Instead, it takes the appearance of an allocation of a "slice" of the system output at the cost of an equivalent portion of the system cost (Composite Cost Pool). Regional leaders involved in creating the TRM wanted to put Slice and non-Slice products on a comparable rate structure. When the TRM was adopted, Bonneville ultimately decided to make all products billed similarly to Slice – with a "percent of system" rate and billing determinant.

- As a result of this rate structure, Bonneville's Tier 1 rate design is unusual. It includes some important concepts like "Load Shaping Charge" and "System Shaped Load".

- Some key questions to investigate include:
  - ✓ *What does it mean that Bonneville's PF contracts are "Take-Or-Pay"?*
  - ✓ *Are Bonneville's Tier 1 Rate Charges largely fixed or largely volumetric?*
  - ✓ *Could a customer cost be reduced by minimizing load?*
  - ✓ *How much am I paying relative to other $/MWh sources of power?*

- Bonneville's current rate design does not feature a specific "Energy Charge." As an alternative to an energy rate, Bonneville publishes a tabulation of the "Equivalent Energy Rates" as a benchmark for comparison to more traditional contract terms.

Load Shaping Charge

The Load Shaping Charge is the reflection of how the Slice rate structure is applied to the Non-Slice Products. To understand what is meant, consider two different "shapes":

- Hydrologic Shape ("System Shape"). There is a varying monthly "shape" to the output of Bonneville's Tier 1 System Capability. Energy that can be expected from that system is influenced by differing seasonal waterflow on the Columbia River: Typically, the month of April provides the smallest amount of energy, and June provides the largest.

- Metered/Scheduled Shape (Actual Load Shape). Customers place a different monthly "shape" on Bonneville. Load Following customers put more load on Bonneville during the coldest days of winter and the hottest days of summer. A flat Block has its own shape. Neither of these load products trace a "shape" which is the same as the System Shape.

When differences between these two shapes appear, Bonneville may have to enter the market to make balancing purchases (to serve load) or balancing sales (to sell surplus). Load Shaping Charge compensates for this difference between resource and load shapes and is computed as follows:

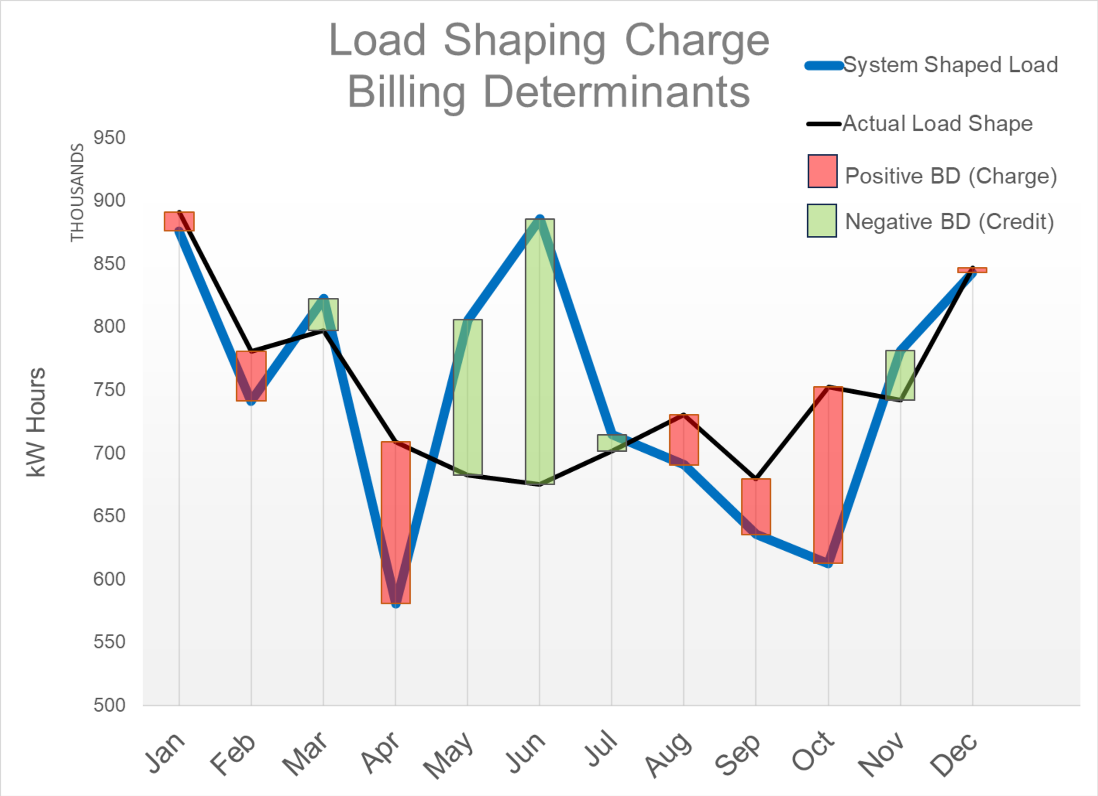
1. Step 1: Calculate a "System Shaped Load" for each customer: Take the customer's forecast Tier 1 Load, and then express it in the *shape* of the forecast firm critical output of the Tier 1 System Resources in each of the 24 monthly/diurnal periods of the year. (Each month is apportioned a part of the total load forecast *as if that month's load conformed* to the same "shape" as the System.)

2. Step 2: Forecast the wholesale market prices for each of the 24 monthly/diurnal periods of the year. (These are the prices that Bonneville would likely encounter when making open market purchases to serve Actual Load Shape when it is different than the System Shape.) This is the Load Shaping Rate.

3. Step 3: Use the meter, or scheduled load, to calculate the Actual Load of the customer. Where served load is greater than the System Shaped Load, register a positive billing determinant. Where served load is lesser than the System Shaped Load, register a negative billing determinant. Multiply the Billing Determinant and the Load Shaping Rate to arrive at the monthly Load Shaping Charge.

Summary: The Load Shaping Charge apportions net balancing purchase costs to each utility based on the customer's contribution to the need for those balancing power purchases. That need exists because of a difference between the Customer's System Shaped Load and actual Bonneville served load.

Load Shaping Charge (cont.)



April HLH Example:

Actual Load: 708,802 kWh
- System Shaped Load: 580,736 kWh
= Billing Determinant = 128,065 kWh

April HLH Rate = $0.02042 / kWh
Charge = BD * Rate = $2,615

June HLH Example:

Actual Load: 675,589 kWh
- System Shaped Load: 885,623 kWh
= Billing Determinant = -210,034 kWh

June HLH Rate = $0.01787 / kWh
Charge = BD * Rate = -$3,753 (Credit)

Load Shaping Charge (cont.)

This is a volumetric charge which is the product of a customer's load (in kWh) and the forecast market price (Mid-C hub) at the time the load is taken. The measurement of the customer's load (billing determinant) is benchmarked not from zero, but instead from the "System Shaped Load." If a customer placed load on Bonneville in the exact shape of its System Shaped Load, then the Load Shaping Charge would net to zero each month for that customer. In this way, Slice and non-Slice products were put on a comparable rate structure.

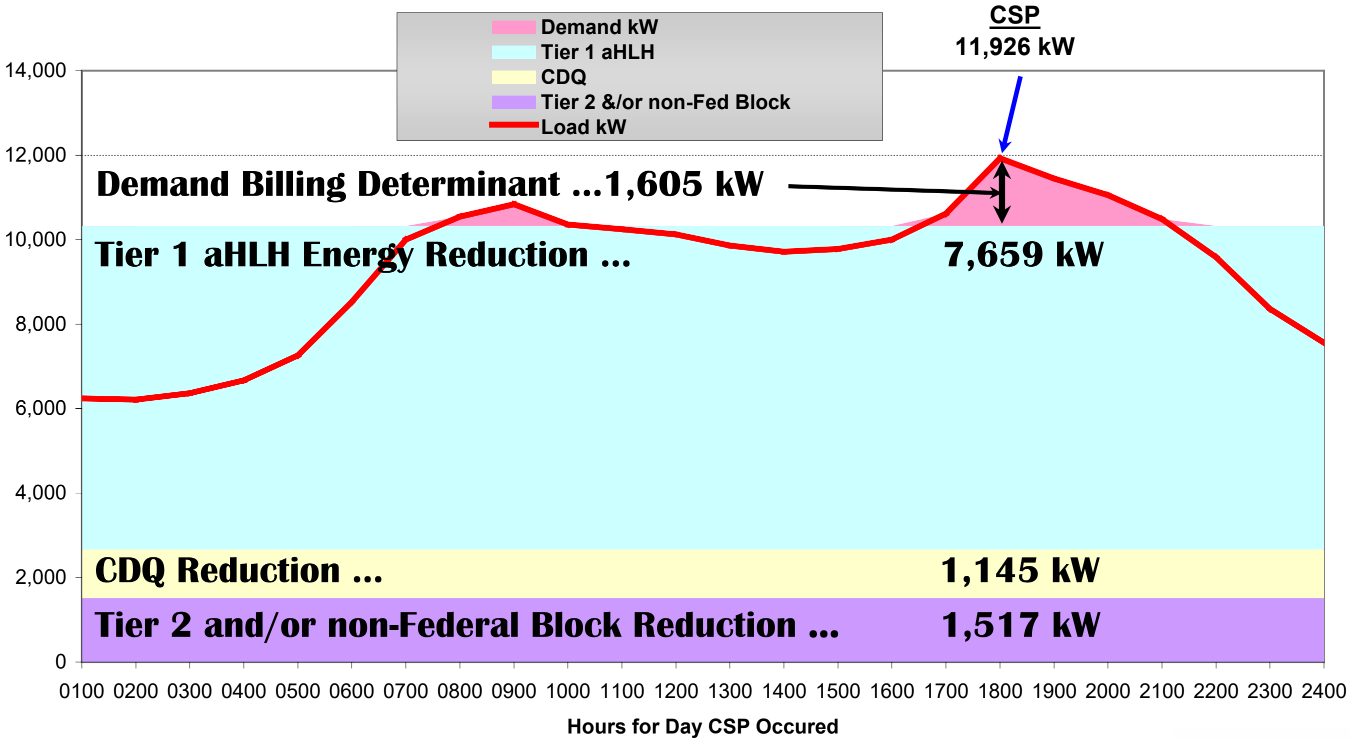
Rate	Market forecast energy prices. The published Load Shaping Rate table is thus a display of the best forecast of Mid-C spot prices.
Billing Determinant	Customer's metered (or scheduled) energy load (kWh) is registered by time of use (24 monthly and diurnal periods a year). The measurement is compared to the "System Shaped Load" benchmark. (Rather than zero.) Thus, the billing determinant can be negative (credit), or positive (charge).
Monthly Rate Difference?	Yes. Every month and every diurnal period has a different Rate. (24 rates per year.) A sophisticated market model creates a spot forecast for each period.
Cost Pool	Net revenue is credited to the Non-Slice Cost Pool. (Any net revenue is returned to customers under the Non-Slice Customer Charge.)
Applicable Products	All Non-Slice PF products. (Slice receives energy in volumes which are the same as the System Shape.)

Demand Charge

A customer "uses" idle capacity by taking a peak load higher than the average load. The Demand Charge is designed to assign the economic cost of idle capacity upon the customers whose usage profile necessitate this idle capacity. The TRM introduced a robust Demand Rate. With the start of the TRM, each customer was provided a customer-specific Contract Demand Quantity ("CDQ") that numerically reduced the demand billing determinant. This was done to moderate the impacts of the new rate.

Rate	Fixed capital cost of the marginal capacity resource. In BP-24, the rate is benchmarked from the Wärtsilä 18V50SG Reciprocating Generator. This rate is currently calculated as ~$9.55/kW/Month.
Billing Determinant	Difference between the customer's Average Load and Peak Load (Both calculated only during during Heavy Load Hours.) With the CDQ, customers were grandfathered approximately 91% of their historical demand. (Subtracting a portion of measured billing determinant.)
Monthly Rate Difference?	Yes. Shaped by market prices during monthly HLH.
Cost Pool	Revenue is credited to the Non-Slice Cost Pool. (Returned as part of the Non-Slice customer credit.)
Applicable Products	All PF Non-Slice products.
Example	Customer System Peak is 10,409 kW. The aHLH Tier 1 is 7,659 akW. The CDQ is 1,145 kW. The Billing Determinant is 10,409 - 7,659 - 1,145 = 1,605 kW. An expected charge is $9.55 * 1,606 kw = $15,337.30 in the month.

Determining Demand Billing Determinant



Demand Charge (cont.)

Super Peak Credit

Some customers can use their own generators to serve loads during peak periods. The Super Peak Credit was an adjustment to the billing determinant of the Demand Charge for Load-Following customers. The Customers could contractually-agree to use their generators and in return get a credit. This was intended to permit the optimization of a customer's Non-Federal resource to serve its own total retail load during certain "Super Peak Periods." The contract commitment was not commonly chosen, even among customers with Non-Federal Resources.

- This was by contractual commitment only.
- The Super Peak Periods were chosen by Bonneville during the rate case.
- The Periods varied by month, either as two three-hour periods each day, or a single six-hour period each day.

Billing Determinant	The reduction in the billing determinant is equal to the amount of additional energy the customer contractually commits to provide from its Non-Federal Resources during each hour of the Super Peak Period compared to the amount of energy that would be provided if the same amount of energy was provided flat within the monthly Heavy Load Hour period.

Slice Customer Charge

This charge was intended as an allocation of the cost of slice implementation to the slice product. By its intent, it would collect costs or return credits specific to the Slice product. As discussed during the last Workshop, the Slice Rate has been $0. This is because there are currently no implementation costs that are allocated to the Slice Cost Pool. For a variety of reasons, Bonneville has never specifically segmented slice implantation expenses during the Regional Dialogue period.

Rate	"$0 per Percentage Point of Billing Determinant per Month."
Billing Determinant	Customer's Slice %
Monthly Rate Difference?	No, each month of the year would have the same charge.
Cost Pool	Slice Cost Pool recovery
Applicable Products	Slice portion of Slice/Block
Example	So far there have been no charges during the implementation of the TRM.

Non-Slice Customer Charge (Credit)

Collects costs or provides credits specific to the Non-Slice products. Historically this has been a monthly net credit. Any surplus sale revenues are assigned to the Non-Slice Cost Pool and credited as part of this Non-Slice Customer Charge. Also affecting this rate is Balancing Power Purchases to serve contractual load, Planned Net Revenues for Risk, and other items.

***Important Note*: Revenues from the *Demand Charges* and the *Load-Shaping Charges* are credited to customers here.**

Rate	Credit of "$364,823 per Percentage Point of Billing Determinant per Month." (In BP-24)
Billing Determinant	Non-Slice TOCA
Monthly Rate Difference?	No, each month of the year has the same credit. (It is "flat" even though Secondary Sales Revenues vary from one month to another.)
Cost Pool	Non-Slice Cost Pool. (This has normally been a credit, because the cost pool has net credits).
Applicable Products	Load Following and Block. (Including the Block portion of Slice/Block.)
Example	A customer has a 10.639 aMW contract eligibility to Tier 1 Power. The sum of all customers is 7107.419 aMW. The Non-Slice TOCA is 0.1497%. The monthly credit is $54,609.

True-Up of Load Shaping Charge

The Tier 1 Rate Design includes a "True-Up" of the Load Shaping Charge for Load Following Customers:

- This is to avoid charging or crediting the market-based Load Shaping Rate for energy within their Tier 1 energy access.

- Bonneville applies this True-Up in various situations when a customer's forecast or actual annual load is less than their "RHWM". This means that their forecast or actual annual load is less than their contract access to power at Tier 1 rates.

Non-Core Charges

Bonneville applies several charges that do not constitute "core charges of the PF Rate design." Several examples of non-core charges are:

- *Targeted adjustment charges*
- *Unauthorized increase charges*
- *Conservation credits or surcharges*
- *Rate adjustments due to risk mitigation (e.g., application of a CRAC)*
- *New or modified risk mitigation tools*
- *Mid-Rate Period rate adjustments for cost recovery purposes*
- *Product switching rates*

The TRM allowed for these non-core charges to be added, subtracted, or modified in each 7(i) Process without a need to change the TRM.

Core Charges By Product Type

The **Non-Slice Customer Charge (Credit)** returns forecast Tier 1 Rate Design Revenues:
- *Demand Revenue*
- *Load Shaping Revenue*

Additionally, the **Non-Slice Customer Charge** (Credit) includes Bonneville's forecast net secondary revenues.

The **Load Shaping Charge** apportions Bonneville's costs of Balancing Power Purchases.

The **Demand Charge** incents responsible attention to capacity-intensive load practices. It is also an equitable apportionment of the costs of capacity.

Load Following Product	Block Product	Slice Product
Composite Customer Charge (TOCA)	Composite Customer Charge (TOCA)	Composite Customer Charge (TOCA)
Non-Slice Customer Charge (Credit)	Non-Slice Customer Charge (Credit)	Slice Customer Charge ($0)
Load Shaping Charge	Load Shaping Charge	
Demand Charge (Signaling Capacity Value)	Demand Charge ($0 because no Peak)	

The **Composite Customer Charge** collects the bulk of the revenue necessary to generate the power delivered to customers.

Open Discussion – Advantages and Disadvantages of the Tier 1 Rate Design

Chapter 5:

Tier 1 Rate Design – New Possibilities

Garth Beavon, Rates Economist

Future Rate Design

Should Bonneville follow the previously established rate structure?

- Bonneville may make various minor alterations (e.g., replacing the CDQ with an alternative rate mitigation device).

Should Bonneville adopt an alternative solution?

- It may be appropriate to eliminate the Diurnal Pricing Construct. Bonneville may also replace the Customer Charges and Load Shaping Charges with a more conventional "Energy Charge."

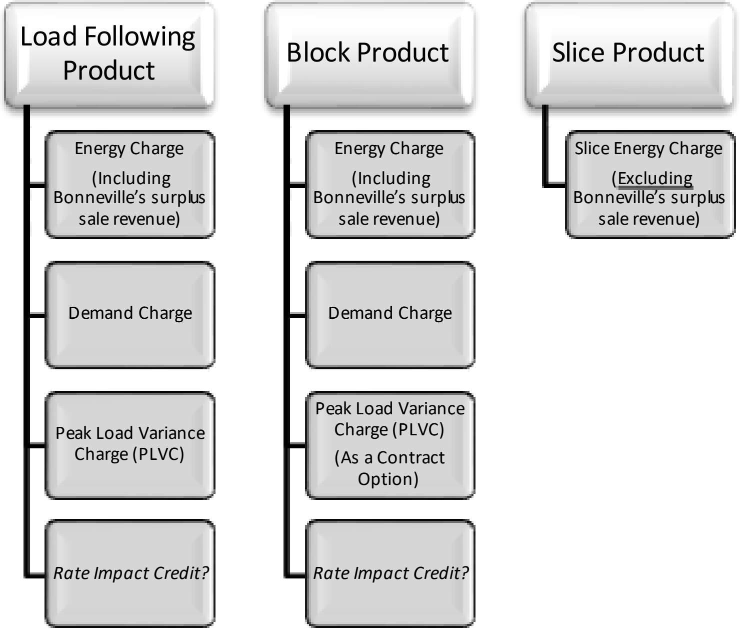
Since the TRM, there have been major changes in the energy industry context:

- A more traditional approach to measuring and charging for capacity use would align with the growing focus on capacity needs as well as provide distinct energy and capacity product price differentiation.

- There is a growing attention toward demand response, resource adequacy, and capacity conservation. It may be important to create a rate redesign in light of these changes.

Possible Future Rate Design

Bonneville may pursue a more conventional rate design with an “Energy Charge.” A new “Peak Load Variance Charge” could specifically allocate the cost associated with Bonneville’s reliability role linked to the Load Following Product. Rate impact mitigation could be addressed with a new specific credit (e.g., a “Rate Impact Credit”.)



The Allocated Tiered Cost Table could be largely sustained. The Composite Cost Pool could be recovered with an “Energy Charge” rather than the Composite Customer Charge.

See later portion of presentation for potential combinations of rate designs Bonneville is evaluating. We encourage you to let us know what designs, **within reason**, you’d like us to evaluate if not on the list.

Peak Load Variance Charge

Purpose of New Charge: A new Peak Load Variance Charge (PLVC) is meant to *unbundle* the cost of meeting variable peak load. It would reflect the resource cost required for Bonneville to have ready and available capacity to meet outlying peak load events (those peak load events greater than normally expected). It represents the difference between the normal expected peak load hour and that peak load of an extreme event or weather situation.

- Under TRM. The cost of capacity to ensure service reliability was implicitly passed through to all customers via the Non-Slice Customer Charge. **The nature of a "Load Variance Charge" was discussed at the time, but through negotiation, a choice was made to leave the cost of this service undifferentiated from the Non-Slice Customer Charge.**

- Under PDRM. A new charge *could* specifically allocate the cost of this service to Power products which utilize this source of capacity. This charge would likely apply to all customers purchasing the Load Following product, and may apply to Block products based upon customer service elections. Customers purchasing the Slice product balance their own loads and resources, and therefore this charge would not apply to Slice.

- Relationship to Western Resource Adequacy Program (WRAP). The PLVC would stand on its own merits if adopted as part of the PRDM future Rate Design. The charge would have a rate and billing determinant which would have their own rules separate from the specific terms governing WRAP. This capacity planning amount is similar to holding the PRM requirement within WRAP, but would follow the rules and requirements outlined for each of Bonneville's products.

Peak Load Variance Charge (cont.)

A PLVC would have rate and billing determinants, established to provide cost recovery of holding planning capacity available for those loads that Bonneville plans for due to load variance responsibilities. In designing a PLVC, various choices would have to be made.

Rate?	• Would it be reflective of Bonneville's embedded capacity cost? (A cost-based rate) • Or would it be reflective of a market-based Marginal Capacity Resource? (Similar to the Demand Rate)
Billing Determinant?	What would be the customer information that Bonneville would use to calculate it? • A customer's Total Retail Load? • Some other billing determinant?
Monthly Rate Difference?	• Would it be logical to have a static ("flat") rate each month across the year? • Or should it be shaped across the months with an energy-market shape?
Cost Pool?	What cost pool would receive the revenues from this charge? • Perhaps the Non-Slice Cost Pool? (Crediting back to the Non-Slice customers)
Applicable Products?	It appears that the charge should apply to the Load Following Product, potentially Block (where contracted-for), but not Slice.
Example	Assuming a rate of $1.25/MWh and a total retail load billing determinant. Load Following customer total retail load of 1,231 MWh in a month. The charge is $1,538.75 for the month, recovering the part of the capacity Bonneville holds to follow the Load Following customer's load.

Demand Charge

The Demand Charge as designed under the TRM appears to serve its function properly. Arguably there may be benefit in further stabilizing it to provide consistency and predictability from one rate period to another. (Instead of being modeled and recalculated each rate period.)

Rate?	- Continue to model a marginal capacity resource? (E.g. the Wärtsilä 18V50SG Reciprocating Generator at ~$9.55/kW/Month.) - Set a definite rate in the PRDM, and then apply an annual inflation adjustment? (E.g. set it at $9.55/kW/Month, and raise it each rate period.) - Set a definite rate, and then alter it only if Bonneville purchases a future capacity resource? - Set the portion of a customer's demand at Bonneville's embedded cost of capacity? (Recently $5.92/kW/Month.)

Demand Charge (cont.)

Billing Determinant?	• Continue to use a monthy Average-to-Top capacity billing determinant? • Use a Bottom-to-Top billing determinant? • Use an "Echeloned Approach": e.g., Bottom-to-Average at Bonneville's embedded rate, and then Average-to-Top at a marginal rate? • Eliminate the grandfathered historical demand (CDQ)? (With rate-mitigation provided through the "Rate Impact Credit.")
Monthly Rate Difference?	Continue to shape across the months in the shape of market energy prices?
Cost Pool?	It appears that revenues should continue to be credited to the Non-Slice Cost Pool.
Applicable Products?	All Non-Slice products (a flat block would have a charge under certain possible billing determinants.)

Energy Charge – A new, yet familiar, energy charge (!)

- $/MWh Rates to potentially replace $ per % TOCA with Load Shaping Rates.
- As an "at cost" marketer of power, Bonneville will collect only as much revenues as necessary to recover cost. Thus, if the PLVC and Demand Charge are levied separately, an Energy Charge would then solve for the energy rates needed to collect the remaining Revenue Requirement.
- Just as is done today with "equivalent rates" in the rate schedules, the energy rates could be given a "market shape", with a numerical scaled adjustment from the forecast market prices. By pricing energy relative to market prices, Bonneville sends economic price signals and allocates costs equitably.
- The Slice energy rate may be higher than the energy rate for the other products, due to the absence of the Secondary Revenue Credit. (That credit is applied to the Non-Slice Cost Pool.) Thus, there may be two different energy rate tables published by Bonneville: One for energy taken under the Load Following and Block products; another for energy taken under the Slice Product.

Energy Charge (cont.)

Rate?	• A dollar-per-megawatt hour rate, set at a level necessary to generate revenues covering the remaining allocated costs. • Will energy be priced diurnally?
Billing Determinant?	• A customer's metered (or scheduled) load.
Monthly Rate Difference?	• Flat across each month of the year? • Shaped across the months with an energy-market shape?
Cost Pool?	• For Slice, the Cost Pool recovered is the Composite Cost Pool. • For Load-Following and Block, the Cost Pool recovered is the combination of the Composite Cost Pool (generation resources) and the Non-Slice Cost Pool (secondary sales revenues and other Non-Slice specific line items).
Applicable Products?	All products. Non-Slice products would have a different rate table than the Slice Product (e.g., Non-Slice products would factor forecast secondary sales revenue.)

Rate Impact Credit (RIC)

A redesign of Bonneville's rate approach may result in sizable rate impacts. How large and where they fall cannot be fully understood until all decisions have been finally made about the future rate design.

When those impacts can be fully analyzed, Bonneville may need to consider developing a "Rate Impact Credit" intended to partially diminish the observed rate impacts.

Features of that credit would also be considered:

- Would it be contractually documented $/MWh amount?
- Would the credit be <u>reduced or changed</u> over the contract period?

TOCA to MWh Proof

$/%
- Customer Rate
  - TOCA or Slice %

$/MWh
- Load Shaping
  - Actual - Plan * $/MWh

$/kW/mo
- Demand
  - CSP – aHLH – CDQ - SuperPeak

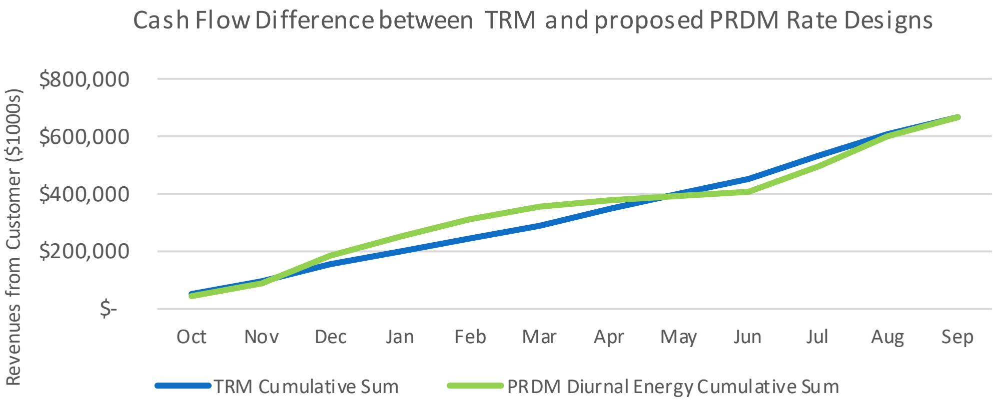
$/MWh
- Energy Rate

$/kW/mo
- Demand

$/MWh
- Peak Load Variance

Revenue Requirement

TOCA to MWh Proof



Example Customer Monthly Bills under TRM Rate Design vs. Shaped Diurnal Energy Charges

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
	TRM													
(1)	Customer Charges (TOCA * Composite+Non-Slice)	$ 54,791,586	$ 54,791,586	$ 54,791,586	$ 54,791,586	$ 54,791,586	$ 54,791,586	$ 54,791,586	$ 54,791,586	$ 54,791,586	$ 54,791,586	$ 54,791,586	$ 54,791,586	
(2)	LS on HLH Energy (Load - System Shaped Load * Market Rates)	$ (1,046,505)	$ (9,638,661)	$ (1,587,163)	$ (7,851,555)	$ (9,947,918)	$ (6,938,219)	$ 649,942	$ (1,368,292)	$ (1,796,538)	$ 11,412,388	$ 15,151,970	$ 1,934,805	
(3)	LS on LLH Energy	$ (405,708)	$ (2,306,865)	$ 2,823,733	$ 2,124,592	$ (579,777)	$ (3,266,970)	$ 893,712	$ 667,971	$ 86,101	$ 9,007,298	$ 10,711,330	$ 2,631,939	
(4)	Total [(2) + (3)]	$ (1,452,213)	$ (11,945,525)	$ 1,236,570	$ (5,726,963)	$ (10,527,695)	$ (10,205,189)	$ 1,543,654	$ (700,321)	$ (1,710,438)	$ 20,419,686	$ 25,863,300	$ 4,566,744	
(5)	Total TRM Charges [(1) + (4)]	$ 53,339,373	$ 42,846,061	$ 56,028,156	$ 49,064,623	$ 44,263,891	$ 44,586,397	$ 56,335,240	$ 54,091,265	$ 53,081,148	$ 75,211,272	$ 80,654,886	$ 59,358,330	$ 668,860,641
	PRDM													
(6)	Energy HLH Charge	$ 32,314,899	$ 26,737,900	$ 59,618,631	$ 44,216,913	$ 36,837,616	$ 25,584,229	$ 12,842,734	$ 12,081,133	$ 12,150,204	$ 57,675,501	$ 75,544,367	$ 44,716,798	
(7)	Energy LLH Charge	$ 13,704,316	$ 14,945,066	$ 35,814,423	$ 23,877,787	$ 20,762,648	$ 17,949,469	$ 9,291,629	$ 7,570,909	$ 3,018,275	$ 25,532,465	$ 32,757,776	$ 23,314,953	
(8)	Total PRDM Diurnal Energy Charges	$ 46,019,215	$ 41,682,966	$ 95,433,054	$ 68,094,701	$ 57,600,264	$ 43,533,698	$ 22,134,363	$ 19,652,042	$ 15,168,479	$ 83,207,966	$108,302,143	$ 68,031,751	$ 668,860,641

Chapter 5:

Design & Scenario Analysis

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Scenario Approach

- We've put forth a few initial scenarios and sample load profiles to:
  - ground understanding
  - describe how designs could affect load profiles
  - develop a sense of the tradeoffs that will occur.

- These scenarios will illustrate mechanics and impacts of different rate designs and build intuition around the kinds of changes we may consider as well as the impacts that could result from those changes.

- As a jumping off point into a discussion around what designs make sense to pursue, like separate rates …
  - On energy
  - On capacity (demand and load variance)

- We anticipate building upon this analysis in the coming months and will ultimately grow into customer impact analysis to discuss and weigh collectively.

Scenario Matrix

- Three main levers shown are changes to the Energy, Demand, and Load Variance Charges
- RIC (Rate Impact Credit) is our place holder for mitigation – it replaces today's CDQ.
- Applied across an initial coarse grouping of load-types for illustration

Scenario:	Energy:	Demand:	Peak Load Variance:	RIC:
Status Quo	Diurnal	Peak-CDQ-aHLH	No	No
Design 1	Diurnal	Peak-aHLH	No	Yes
Design 2	Diurnal	Peak-aHLH	Yes	Yes
Design 3	Average	Peak-aMonthly	No	Yes
Design 4	Average	Peak-aMonthly	Yes	Yes
Design 5 (not yet evaluated)	Average	Echeloned Approach	Yes	Yes

Sample Load Profiles

- A few load profiles were selected to illustrate mechanics
- Load Factor: how a load's peak compares to monthly average consumption
- Shape: does the load have a typical seasonality, or is it skewed heavily due to irrigation

Load Characteristics	Load Factor	Shape
A	40%	Normal
B	70%	Normal
C	70%	Irrigation Heavy
D	90%	Normal
E	100%	Normal

Modeling Assumptions

- Model drafted to evaluate 5 types of customers
  - Uses data from TRMbd
  - Fifth customer type 100% load factor/Block-only calibrated to 50% of load-following load and split into two customers
  - Block shape is composite of Monthly Shaping factors in the TRM

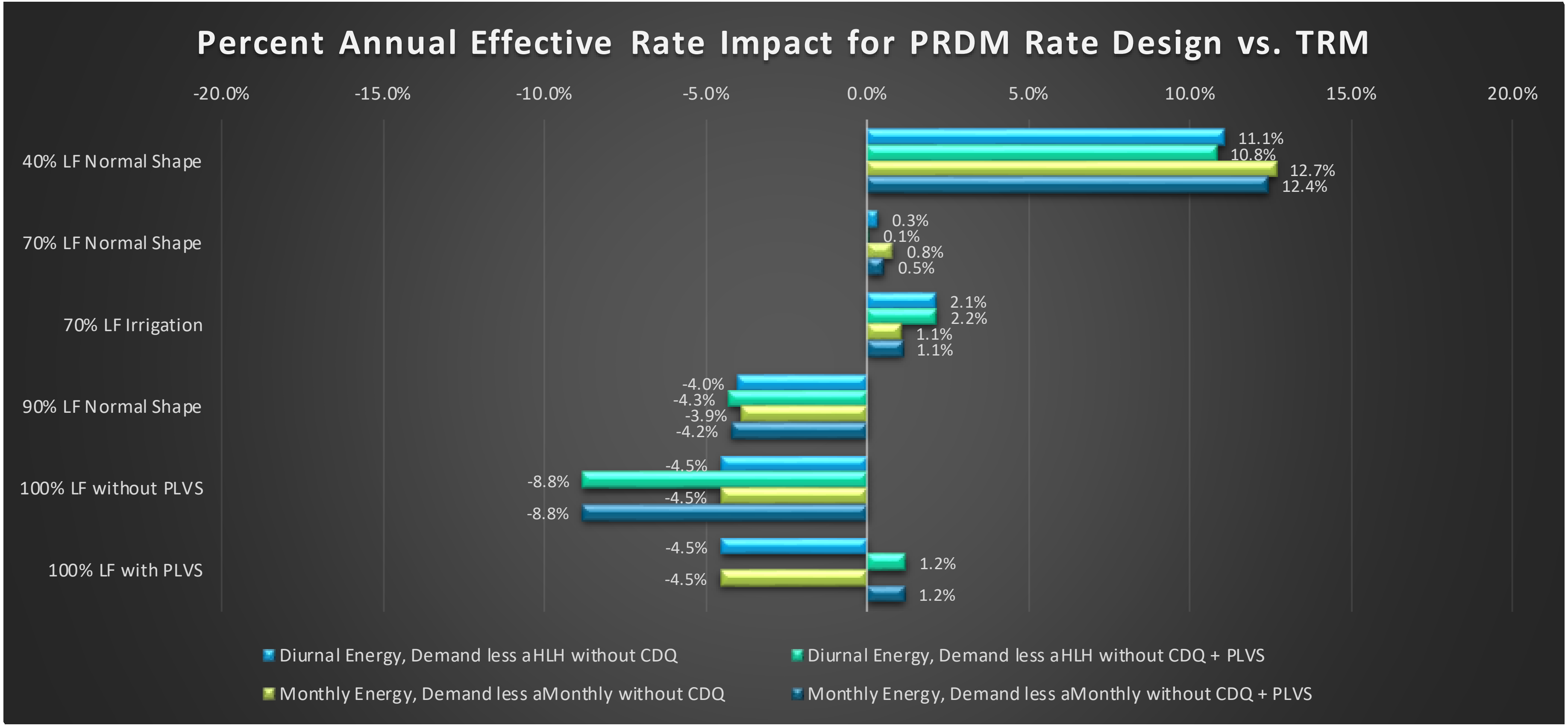
- Load factors are calculated based upon the average annual energy to annual peak

- Net Requirement (NR) loads assumed in all calculations but for PLVS, which is allocated and charged based upon Total Retail Load (TRL). Block TRL is assumed to be 25% higher than the customers' NR.

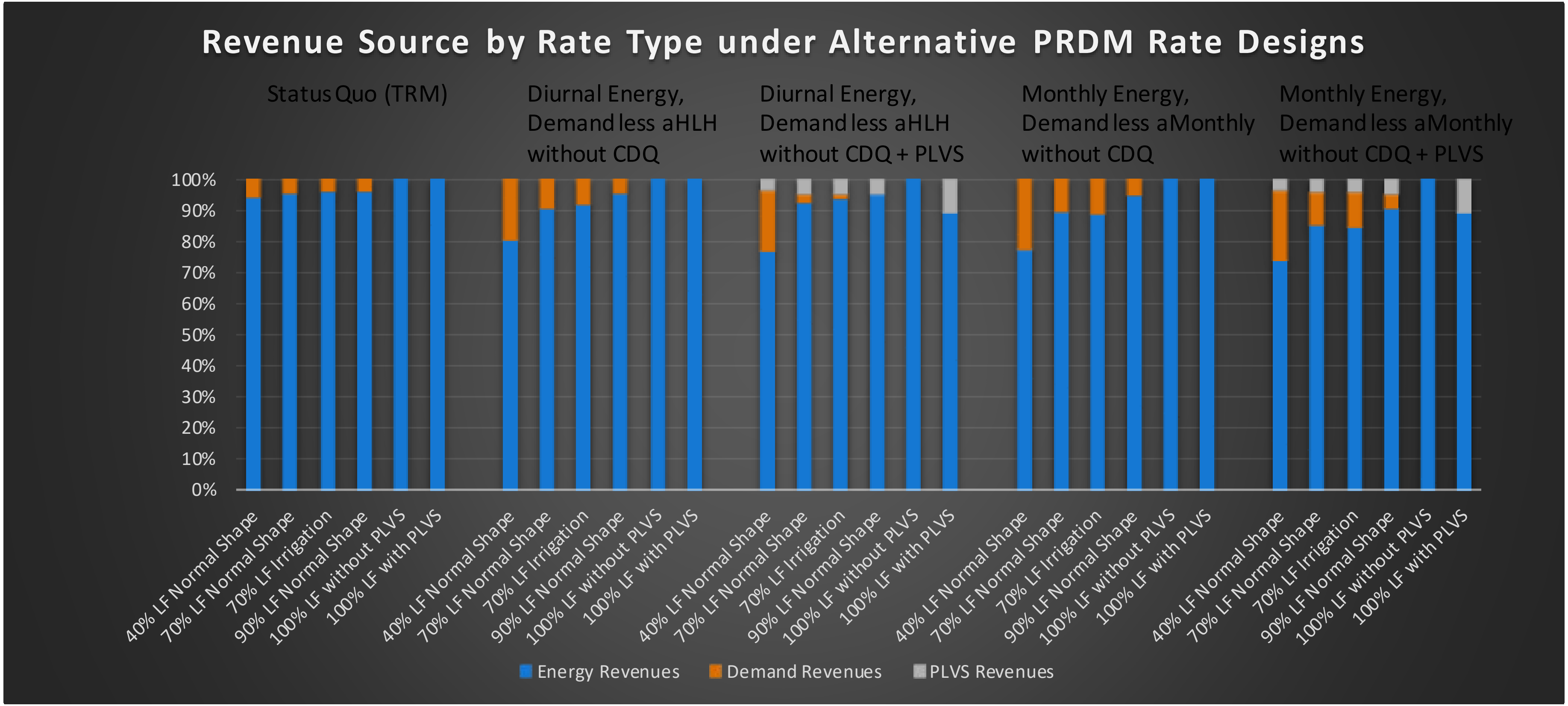
- These impacts are for illustrative purposes and assume a customer composition that isn't currently calibrated to the actual system makeup.

Results Summary

Annual Average Effective Rate	Status Quo	Rate Design 1	Rate Design 2	Rate Design 3	Rate Design 4
Diurnal	YES	YES	YES	NO	NO
Demand Billing Determinant	Peak minus CDQ minus aHLH	Peak minus aHLH	Peak minus aHLH	Peak minus aMonthly	Peak minus aMonthly
Peak Load Variance Rate (PLVS)	NO	NO	YES	NO	YES
40% LF Normal Shape	38.06	38.32	38.26	38.56	38.49
70% LF Normal Shape	33.42	33.32	33.24	33.09	33.02
70% LF Irrigation	33.83	33.67	33.77	33.88	33.98
90% LF Normal Shape	31.32	31.05	30.97	30.67	30.59
100% LF without PLVS	31.08	30.68	28.30	30.26	27.89
100% LF with PLVS	31.08	30.68	34.14	30.26	33.72



Percent Annual Effective Rate Impact for PRDM Rate Design vs. TRM
-20.0%
-15.0%
-10.0%
-5.0%
0.0%
5.0%
10.0%
15.0%
20.0%
40% LF Normal Shape
11.1%
10.8%
12.7%
12.4%
70% LF Normal Shape
0.3%
0.1%
0.8%
0.5%
70% LF Irrigation
2.1%
2.2%
1.1%
1.1%
90% LF Normal Shape
-4.0%
-4.3%
-3.9%
-4.2%
100% LF without PLVS
-4.5%
-8.8%
-4.5%
-8.8%
100% LF with PLVS
-4.5%
1.2%
-4.5%
1.2%
Diurnal Energy, Demand less aHLH without CDQ
Diurnal Energy, Demand less aHLH without CDQ + PLVS
Monthly Energy, Demand less aMonthly without CDQ
Monthly Energy, Demand less aMonthly without CDQ + PLVS


Revenue Source by Rate Type under Alternative PRDM Rate Designs
Status Quo (TRM)
Diurnal Energy, Demand less aHLH without CDQ
Diurnal Energy, Demand less aHLH without CDQ + PLVS
Monthly Energy, Demand less aMonthly without CDQ
Monthly Energy, Demand less aMonthly without CDQ + PLVS
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
40% LF Normal Shape
70% LF Normal Shape
70% LF Irrigation
90% LF Normal Shape
100% LF without PLVS
100% LF with PLVS
Energy Revenues
Demand Revenues
PLVS Revenues

Scenarios and Modeling Next Steps

- Identify full list of rate designs we want to consider. We can always come revisit later if needed.
- Apply to all customers based on historical load shapes and different possible rate designs.
- Select the top rate designs and design the methodology for the Rate Impact Credit (RIC).
- Rerun analysis with RIC applied.
- Consider, tweak, and compromise so that chapter 5 can be drafted.

Conclusion & Next Steps

March and April Workshops

Workgroup 3/7

March 19, Workshop #4	• Chapter 5: Tier 1 Rate Design (Cont.) • Chapter 6: Tier 2 Rate Design
April 29, Workshop #5	• Chapter 8: Resource Support Services

2029 PRDM

- Definitions
- Chapter 1 – Background & Purpose
- Chapter 2 – Cost Allocation
- Chapter 3 – Federal System
- Chapter 4 – T1 Eligibility (CHWM) Move to POC
- Chapter 5 – Tier 1 Rate Design
- Chapter 6 – Tier 2 Rate Design
- Chapter 7 – Shared Rate Plan – Delete
- Chapter 8 – RSS
- Chapter 9 – Risk Mitigation
- Chapter 10 – Other Rate Design
- Chapter 11 – Approval and Duration – Delete/Move
- Chapter 12 – Conditions for Revision
- Chapter 13 – Revision Processes

Thank you

For feedback, questions, comments please email: **prdm@bpa.gov**

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