



Post-2028 Residential Exchange Program

7(b)(2) Legal Interpretation and Implementation Methodology Process

October 22, 2026

9:00am – 3:00pm

Rates Hearing Room and Webex



Day 1 Agenda

	Workshop Topics	Presenter(s)
9:00 – 9:20	Agenda and Introductions, Process Overview	Sarah Burczak
9:20 – 10:00	History and Background	Richard Greene
10:00 – 10:30	The REP in Practice	Richard Greene
10:30 – 10:45	Origins of LI & IM	Richard Greene
10:45 – 11:00	Break	~
11:00 – 11:45	Updated Assumptions and Scenarios	Stephanie Adams
11:45 – 12:15	Settlement Concepts and Opportunities	Richard Greene & Daniel Fisher
12:15 – 1:15	Lunch	~
1:15 – 2:50	Technical Workshop: 7(b)(2) Deep-dive & Historical Interpretation	Jonathan Ramse & Richard Greene
2:50 – 3:00	Next Steps / Close Out	Daniel Fisher

Day 2 Agenda – Technical Workshop

	Workshop Topics	Presenter(s)
9:30 – 9:40	Agenda Overview	Sarah Burczak
9:40 – 10:00	Technical Workshop: Continue 7(b)(2) Deep-dive & Historical Interpretation	Jonathan Ramse & Richard Greene
10:00 – 11:30	RAM Modeling including Scenarios and How to Operate the Model	Stephanie Adams
11:30 – 11:50	Technical Questions	REP Team
11:50 – 12:00	Next Steps / Close Out	Sarah Burczak

Post-2028 REP Team

- Daniel Fisher, REP Sponsor (VP, NW Requirements Marketing)
- Aimee Robinson, REP Policy Lead
- Michael Edwards, REP Technical Lead
- Richard Greene, Legal Counsel
- Neal Gschwend, Legal Counsel
- Stephanie Adams, Rates and 7(b)(2) Lead
- Jonathan Ramse, Economist
- Sarah Burczak, Power Rates Manager
- Scott Winner, PSRF Supervisor

7(b)(2) LI & IM Process

Process Overview

Sarah Burczak

Power Rates Manager

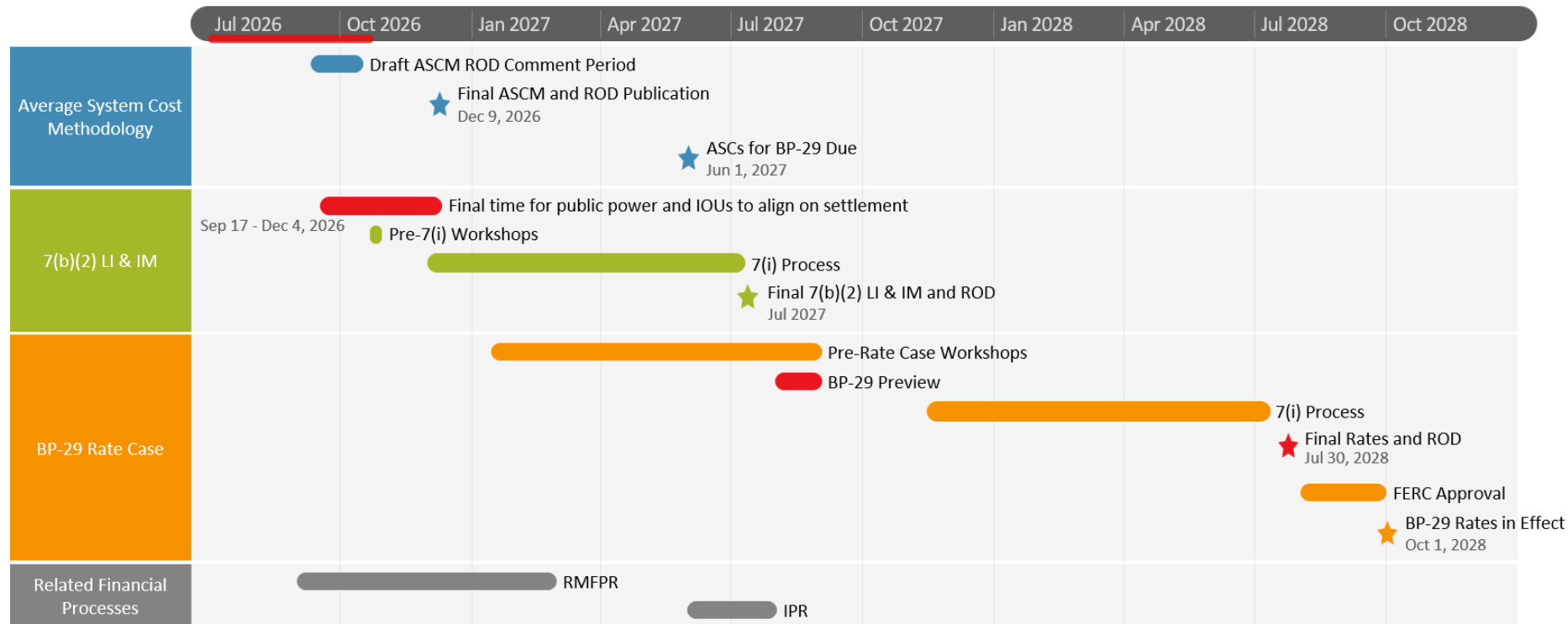
Phase 2 Public Engagement Process

Phase 2 focuses the Post-2028 REP Public Engagement Process on development of three foundational components to prepare for a traditional implementation of the REP post-expiration of the 2012 REP Settlement agreements. The 2012 Settlement expires September 30, 2028.

1. Residential Purchase and Sale Agreements (RPSA)
2. Average System Cost Methodology (ASCM)
3. **7(b)(2) Legal Interpretation and Implementation Methodology**



7(b)(2) and Other Relevant Timelines



Dates are subject to change

Communication and Resources

- Submit written comments and questions to rep2028@bpa.gov.
- Details to attend all Post-2028 REP Phase 2 workshop can be found on [BPA's event calendar](#).
- For REP background, Post-2028 public workshop materials, public notices, and additional REP resources, go to the [Post-2028 REP webpage](#).
- To receive pertinent notifications related to this process, sign up for [Tech Forum](#).

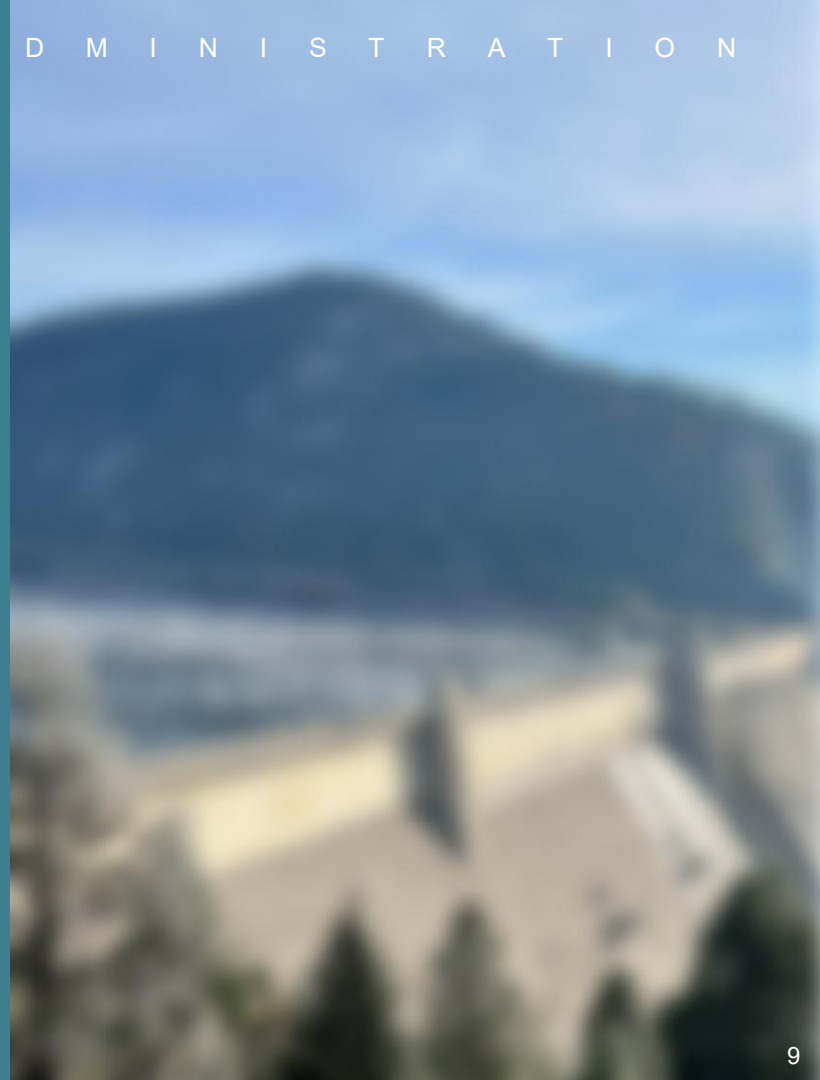
7(b)(2) LI & IM Process

History and Background

Richard Greene

Senior-Attorney Advisor

POST
2028
REP



What is the Residential Exchange Program?

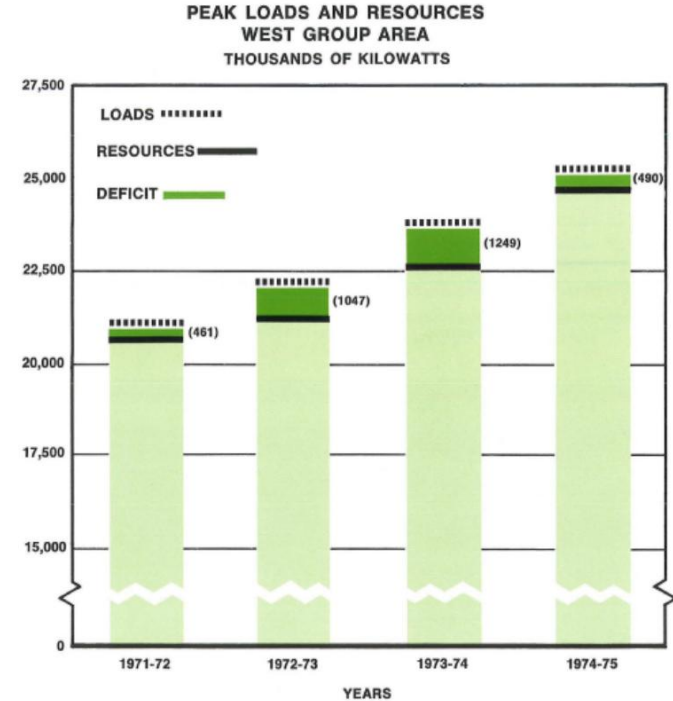
- Enacted by Congress under Section 5(c) of the 1980 Northwest Power Act to address wholesale rate disparity between Investor-Owned Utilities (IOUs) and PF customers (COUs) in the Pacific Northwest.
 - In simple terms: the REP is a federal program that provides economic benefits of the federal system to residential and farm customers of participating utilities.

Balance forward	0.00
Previous amount due 8/8/22	151.62
Payments through 8/19/22	151.62 ^(CR)
	200.37
Energy charges	192.10
Basic Charge	11.00
Energy Use Charge (1,000.000 kWh x \$0.06642)	66.42
Energy Use Charge (420.000 kWh x \$0.07002)	29.41
Transmission Charge (1,420.000 kWh x \$0.00585)	8.31
Distribution Charge (1,420.000 kWh x \$0.0542)	76.96
Regulatory charges and credits	3.90
102 RPA Exchange Credit (1,420.000 kWh x \$-0.00676)	9.60 ^(CR)
105 Regulatory Adjustments (1,420.000 kWh x \$-0.0001)	0.14 ^(CR)
109 Energy Efficiency Funding Adj (1,420.000 kWh x \$0.00579)	8.22
110 Energy Efficiency Customer Svc (1,420.000 kWh x \$0.00008)	0.11

112 Customer Engagement Transformation Adjustment (1,420.000 kWh x \$0.0003)	0.43
118 Bill Adjustment Cost Recovery	0.23
123 Decoupling Adjustment (1,420.000 kWh x \$-0.00227)	3.22 ^(CR)
135 Demand Response (1,420.000 kWh x \$0.0006)	0.85
136 Community Solar Cost Recovery (1,420.000 kWh x \$0.00006)	0.09
137 Solar Payment Option Cost Recov (1,420.000 kWh x \$0.00005)	0.07
138 Energy Storage Cost Recovery (1,420.000 kWh x \$0.00004)	0.06
143 Spent Fuel Adjustment (1,420.000 kWh x \$-0.00019)	0.27 ^(CR)
146 Colstrip Power Plant Oper Life Adj (1,420.000 kWh x \$0.0044)	6.25
150 Transportation Electrification (1,420.000 kWh x \$0.00058)	0.82
Other charges and credits	0.51

History: The View from Circa 1960s & 1970s

- “The forecast indicates that Northwest electric energy requirements **will triple in the next 20 years** and that within a few years . . .” (BPA’s Annual Report, December 31, 1970.)
- 7% load growth across the region
- In 1973:
 - BPA stopped selling to IOUs.
 - BPA periodically reduced sales to DSIs, and would not renew contracts post expiration.
- In 1976: BPA issued a “notice of insufficiency” to its preference customers.
 - Notified preference customers that BPA would be short on power by 1983.
 - BPA would have to allocate federal power among preference customers.

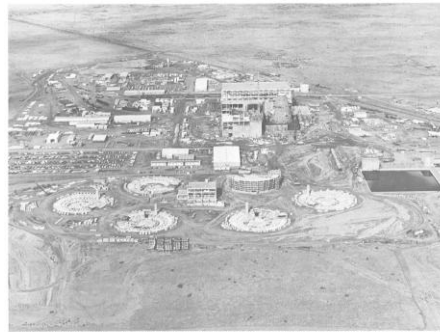


The Hydro-Thermal Power Program & Issues

- In 1968, BPA and over 100 utilities outlined the Hydro-Thermal Power Program (HTPP) to supply the region through 1981.
- Federal, private and public utilities collaborated to build generation and transmission.
- HTPP proposed developing **20 nuclear plants and two coal plants**, projected to cost \$17.9 billion (~\$141 billion today).

Problems with the HTPP

- Reduced forecast for power
- Cost overruns
- Construction delays
- Community opposition
- Environmental opposition
- Court injunction: BPA's participation in Phase 2 paused until BPA completed an EIS



By the end of October 1976 overall construction of Washington Public Power Supply System's Nuclear Project No. 2 was about 26 percent complete. Plant's six circular cooling towers are being constructed in the foreground. (photo courtesy of WPPSS)



The 1,120,000-kilowatt Trojan Nuclear Plant, which first put power into the Pacific Northwest grid in December 1975.

Rate Disparity: Publics and Private

- HTPP costs included in rates meant costs of serving customers of IOUs and COUs rapidly increased.
- IOUs' consumers were hit harder, paying 3x what public consumers paid.
- BPA required by federal law to serve COUs' needs first (preference).
- Only sell to IOUs if surplus available.
- As rates between private and public utilities diverge, political pressure builds to provide consumers of IOUs with a share of low-cost federal power.

WEDNESDAY, APRIL 12, 1978

Governors split over power plan

By ED MOSEY
of The Oregonian staff

BOISE — Gov. Bob Straub demanded principles; Gov. Dixy Lee Ray of Washington insisted on specifics, and

Gov. John Evans of Idaho joined Straub in supporting a larger share of hydroelectric power for residents of other states that now are served by private utilities.

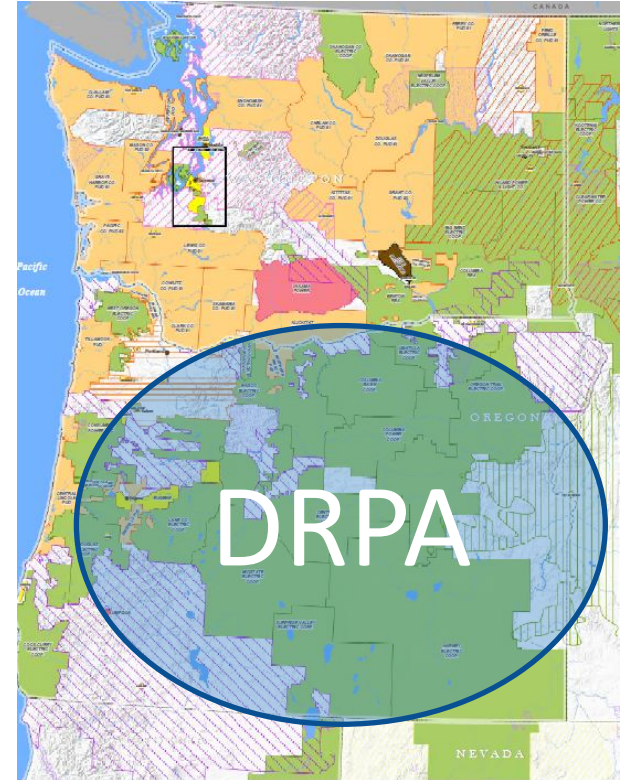
Straub said the governors should agree in principle that customers of private utilities in the Northwest should get an "equitable" share of the electricity generated by dams on the Columbia River system.

"People in Portland are paying \$27 for electricity people in Vancouver are paying \$11 for," he said. "The general public should have equal access."

Customers of public utilities now are guaranteed preferential treatment in the allocation of power generated by federal projects on the Columbia River system.

Preference and Regional Division

- Washington is primarily served by COUs.
- Oregon is served primarily by IOUs.
- Turning Point: In an effort to gain access to a share of cheaper BPA power, Oregon prepared legislation creating “Domestic and Rural Power Authorities” (DRPA).
 - DRPA would sell power to IOUs’ consumers at a melded rate (some DRPA and some IOU).
 - DRPA would have asserted rights as a BPA preference customer.
- Other states considered proposing the same type of legislation. This opened the door to a regional fight over BPA’s allocation of power.



The Northwest Power Act (NWPAct) and REP

- To avert conflict, Congress passed the NWPAct in 1980.
- One aspect of the NWPAct was the REP, which was designed to help address the wholesale rate disparity between residential and farm customers in IOU vs. COU territories.
- NWPAct created an “exchange” between IOUs and BPA to residential and farm customers access to economic value low-cost federal power.
- Preference battle was avoided.
 - IOUs’ consumers received some economic value from federal projects. COUs received no diminishment in the amount of power sold to them, and “rate protection” through Section 7(b)(2) of the NWPAct.
- The first 5 years of REP implementation was paid exclusively by DSIs. 7(b)(2) rate protection did not kick in until 1985.



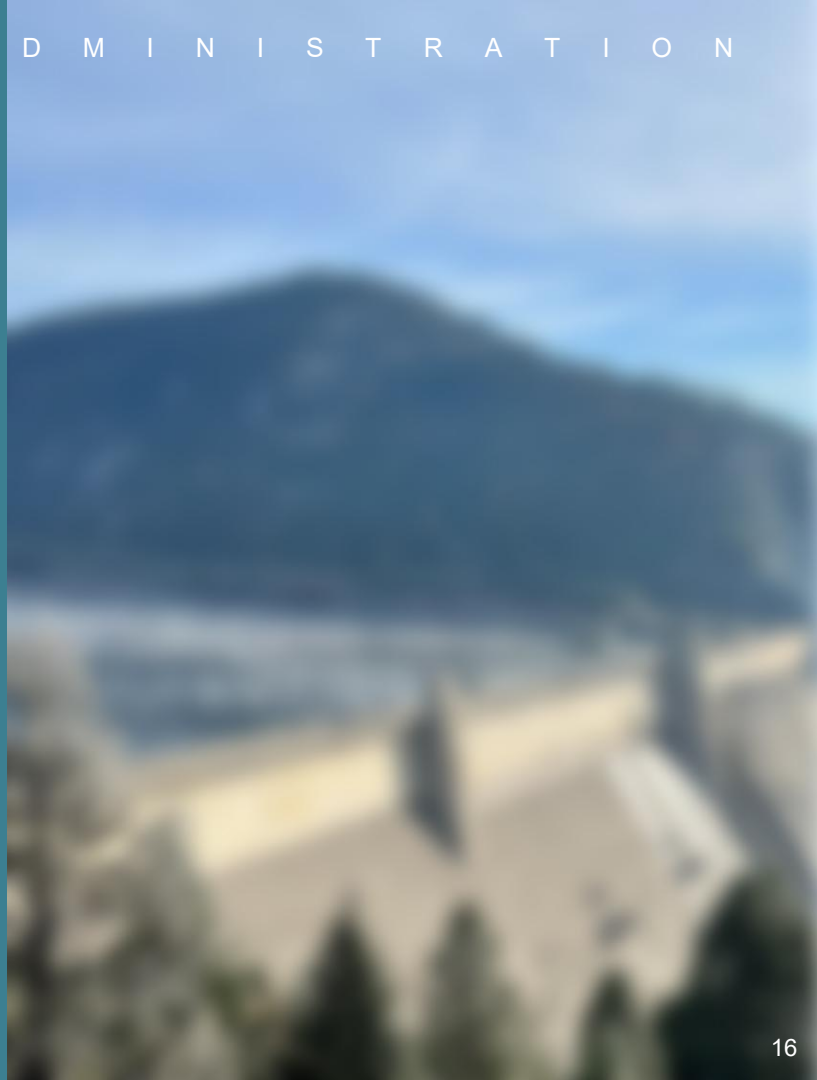
7(b)(2) LI & IM Process

The REP In Practice

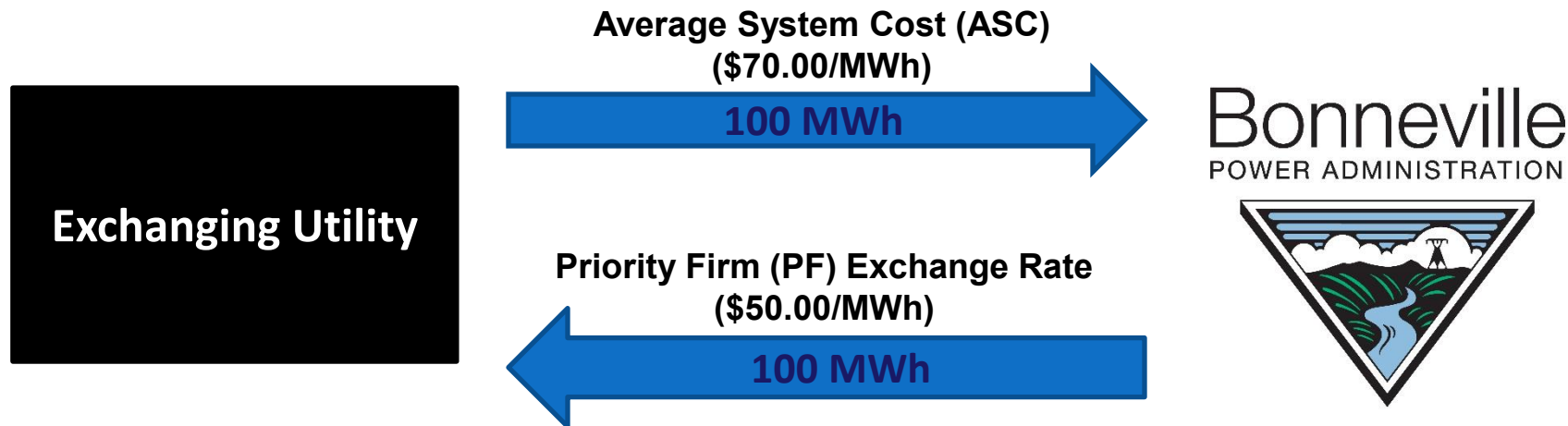
Richard Greene

Senior-Attorney Advisor

POST
2028
REP



Calculating the REP Payment



- $(\text{ASC} - \text{PF Exchange Rate}) \times \text{Residential and Farm Load} = \text{REP } \$\$$
- $(\$70 \text{ MWh} - \$50 \text{ MWh}) \times 100 \text{ MWh} = \2000 (“REP benefit”)
- No actual power exchanged. Just a “paper transaction.” (See, however, *in lieu* under Section 5(c)(5)). (Issue is currently in dispute).

Calculating REP Benefits per Statute

Section 5(c) of NWPA
(ASC Methodology)

Sections 3(18),
5(c)(1)/(2) of NWPA

$(\text{Average System Cost} - \text{PF Exchange Rate}) \times \text{Res\&Farm Load} = \text{REP } \$\$$

Section 7(b)(2) of NWPA
(Legal Interpretation)
(7(b)(2) Methodology)

What is the PF Exchange Rate?

- The PF Exchange rate begins *the same* as the PF rate!
- Section 7(b)(1) requires BPA to meld the costs of the FBS and IOU exchange resources together in one rate pool (initially).
 - This feature creates the “economic” sharing of the low-cost federal power with IOUs.
- BPA has historically called this pre-7(b)(2) PF rate the “**Unbifurcated**” PF rate.
- The Unbifurcated PF rate is HIGH compared to PF Rate.
 - Takes the raw delta between BPA’s PF rate with IOU exchange resources.
 - Around \$57/MWh because REP benefits in 7(b)(1) is around \$900M.
- If NO 7(b)(2) rate test, this would be the PF rate for *both* COUs and IOUs.

Why a Rate Test?

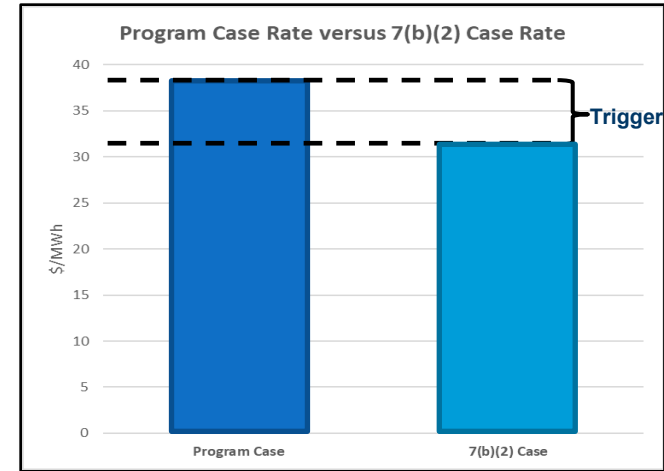
- Initial versions of the NWPA did *not* contain a rate test.
 - The general benefits of the Act were thought to be sufficient to offset the increased costs that could be imposed by the REP.
 - Acquisition authority reduced financing costs because BPA became an anchor tenant on resources acquired by Public Power.
 - Avoided DSIs from converting to Public Power, exacerbating the power deficits
- Key assumptions in making this true:
 - DSIs were expected to be around (3300aMW).
 - WNP 1 and 3 were expected to be built.

Trust, but Verify....

- Public Power wanted to ensure the new provisions of the Act would not diminish their preference rights or dilute their power rates in a way that would result in higher rates than without the Act.
- To protect preference, the Act includes Section 5(a) and Section 10(c).
- To protect price, the Act includes the Section 7(b)(2) “rate test”.

Overview of the Section 7(b)(2) Test

- **The Rate Test can be considered an ongoing cost-benefit analysis.**
 - It compares projected rates set to recover certain power costs included in the NWPA (**Program Case**) to a hypothetical rate set to recover power costs assuming certain features of the NWPA were not in place (**7(b)(2) Case**).
 - The Rate Test is intended “to assure that the financial benefits of the preference clause in the Bonneville Act will continue to accrue to BPA preference customers.” Sen. Rep., Appendix B
- **Functionally, the Rate Test limits the amount of REP costs that may be recovered in the PF rate.**
 - If the 7(b)(2) Case Rate is higher than Program Case Rate, pass the test, and BPA can charge the Unbifurcated PF Rate.
 - If the **Program Case rate** is higher than the **7(b)(2) Case rate**, then the Rate Test is said to “trigger” and the difference between the \$/MWh is multiplied by PF customer load to establish a rate protection amount.
 - The rate protection amount is then allocated away from PF customer loads to all other power sold as a supplemental rate charge.



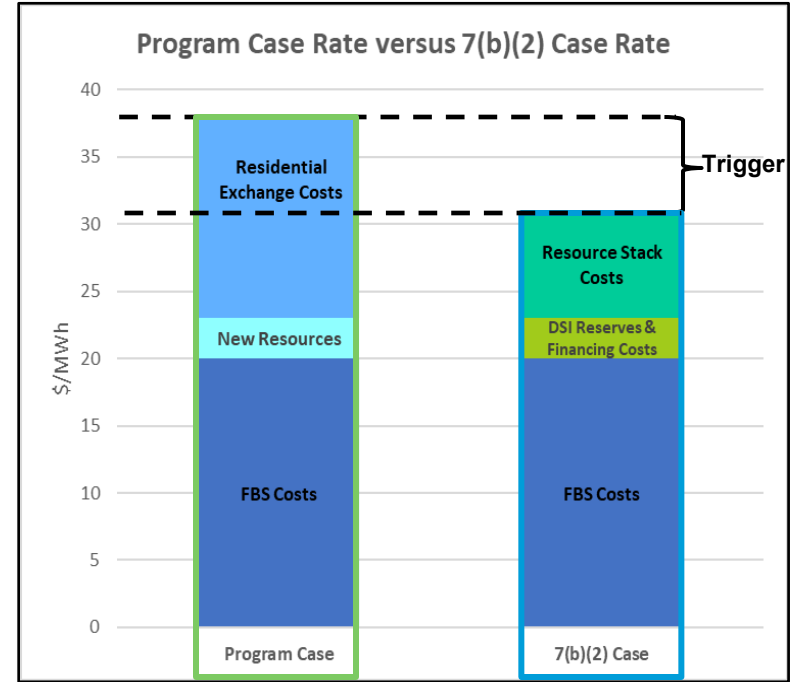
Section 7(b)(2) of the Northwest Power Act

After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) of this section for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator assumes that—(A) the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are—(i) served by the Administrator, and (ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives; (B) public body, cooperative, and Federal agency customers were served, during such five-year period, with Federal base system resources not obligated to other entities under contracts existing as of December 5, 1980, (during the remaining term of such contracts) excluding obligations to direct service industrial customer loads included in subparagraph (A) of this paragraph; (C) no purchases or sales by the Administrator as provided in section 839c(c) of this title were made during such five-year period; (D) all resources that would have been required, during such five-year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were—(i) purchased from such customers by the Administrator pursuant to section 839d of this title, or (ii) not committed to load pursuant to section 839c(b) of this title, and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator; and (E) the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from—(i) reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) of this paragraph, and (ii) reserve benefits as a result of the Administrator's actions under this chapter were not achieved.

“...a Byzantine sentence that nearly fills a page and that is, in my view, the most complicated section in the Act.” – Steve Wright, WP-07 Supplemental ROD

Components of the Section 7(b)(2) Test

Step 1	Exclude specific Section 7(g) Costs from Program Case	Conservation costs, experimental resource costs, billing credits costs, and “uncontrollable events” costs
Step 2	Run the five assumptions of the 7(b)(2) rate test (Alternative Test Case as directed by Congress)	<p>(A) DSIs are served by their local utility instead of BPA</p> <p>(B) Federal Base System resources are used for publics first</p> <p>(C) no REP purchases and sales</p> <p>(D) after the FBS is exhausted, other resources owned by publics are applied in least cost order</p> <p>(E) power reserve benefits and reduced financing costs available under the Act are not achieved</p>
Step 3	Compare the rates produced by Program Case with the 7(b)(2) Case	<ul style="list-style-type: none"> - Produce five-year projection of Program Case Rate and 7(b)(2) Case Rate. Historically, discount both. - If Program Case rate is lower, do nothing; if 7(b)(2) Case rate is lower, rate test triggers. The \$/MWh difference between the two rates is multiplied by the PF customer load to determine a rate protection amount.
Step 4	Allocate difference from Step 3 to other rates	The rate protection amount from Step 3 must be allocated to other non-PF power sold per 7(b)(3).



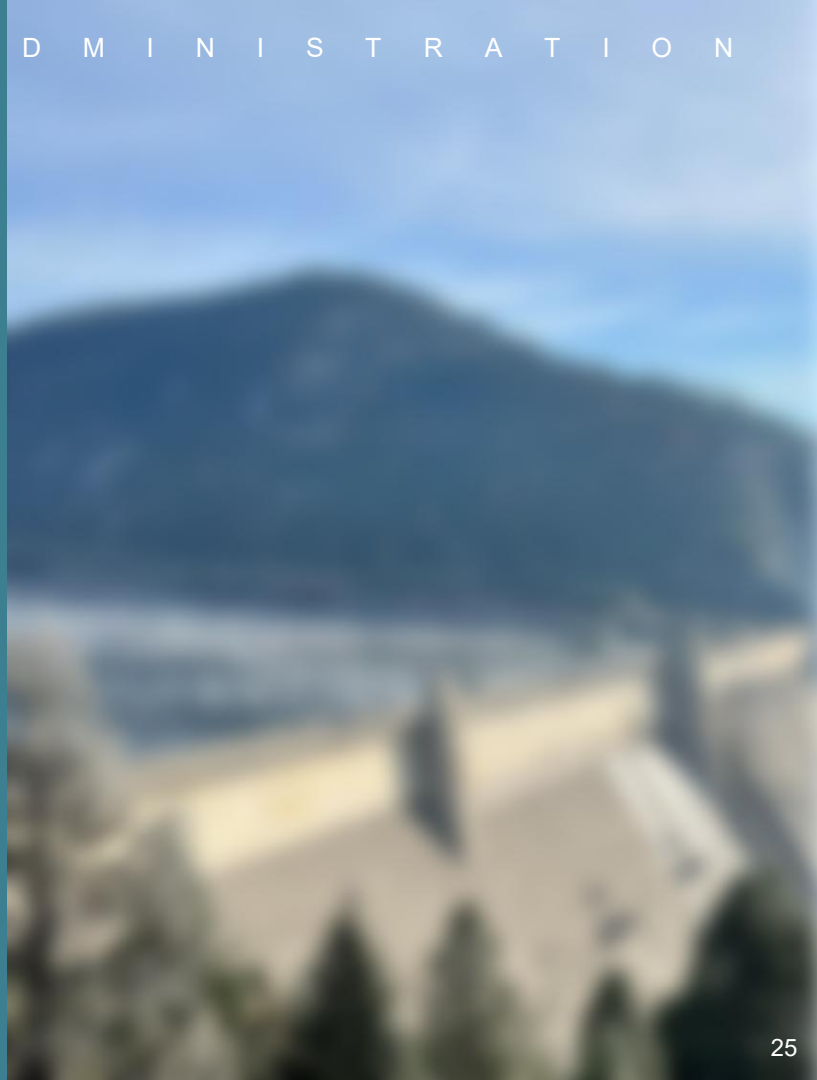
7(b)(2) LI & IM Process

Origins of LI & IM

Richard Greene

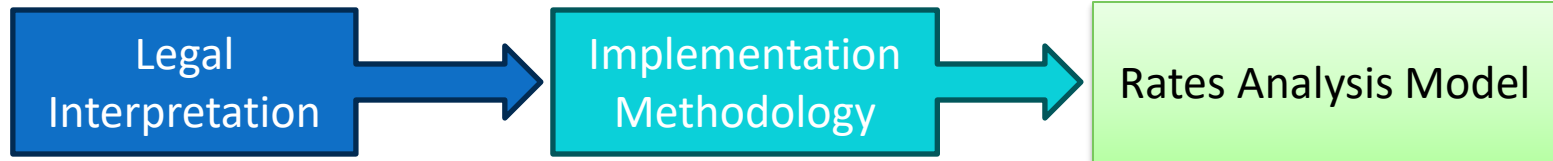
Senior-Attorney Advisor

POST
2028
REP



Section 7(b)(2) Legal Interpretation and Implementation Methodology

- The NWPA does not require BPA to develop either a Legal Interpretation or Implementation Methodology for Section 7(b)(2)/(3).
- However, since 1985 (the first year 7(b)(2) was active), BPA has developed both. Why?
 - 7(b)(2) is complicated and having an LI/IM helps BPA and the parties frame issues.
 - The test is functionally run through a model – **Rates Analysis Model (RAM)**.
 - LI/IM guide the operator of RAM to ensure that the model is producing results consistent with the intended interpretations.



Status of the LI and IM

- BPA currently has no LI or IM for Section 7(b)(2).
- In 1985, developed both, but:
 - 1985 LI and 1985 IM were never challenged.
 - Section 7(b)(2) rarely triggered because of DSI loads.
 - Multiple settlements through the 1990s.
- In 2008, following remand from the Court in *PGE*, BPA revised the LI and IM.
 - 1985 LI / 1985 IM were revised and replaced with 2008 LI / 2008 IM. Both were challenged in the Ninth Circuit.
- 2012 REP Settlement
 - In the 2012 REP Settlement, BPA agreed to withdraw its LI and IM in their entirety.
 - BPA agreed to hold a proceeding to prior to FY 2029 on whether, and if so how, to revise its LI and IM.

Process for developing the LI and IM

- BPA has historically used its Section 7(i) process to develop both the LI and IM.
 - **1985.** LI was developed just before the 7(i) in 1985, and only the IM went through 7(i). Resulted in odd timing for issues in the 7(i) proceeding.
 - **2007-2008.** Both the LI and IM went through 7(i). The LI and IM were attached to the Section 7(b)(2) Study in rate case. All 7(b)(2) issues were decided in one decision.
- Why a 7(i) Process?
 - Process allows for the development of a robust record.
 - The 7(b)(2) Implementation Methodology will be used in future ratemaking, and thus, a Section 7(i) process provides some procedural protections in case ratemaking does become an issue.
 - Formal briefing allows parties to see and fully develop all legal and policy issues with Section 7(b)(2).
- At this point, BPA intends to use the Section 7(i) process again to develop the LI and IM.
 - NOTE: Like PRDM, BPA will *not* file the LI/IM with FERC at end of proceeding.
 - The LI and IM will be used in BP-29 rate setting. The LI and IM will be *outside of scope* of proceeding (though implementation will be within scope).

7(b)(2) LI & IM Process

Updated Assumptions and Scenarios

Stephanie Adams

Rates and 7(b)(2) Lead

POST
2028
REP

Assumptions Used in the Modeling

- Data used in RAM for the scenario analysis is primarily from the BP-26 rate case. Inputs were collected in September 2024.
- Data that has been updated in all models since BP-26 is noted below:
 - Resource stack: Staff updated the Resource Stack to capture Grant's available Mid-C resources (Priest Rapids Project). This large-quantity (~260aMW) low-cost resource puts downward pressure on REP benefits.
 - ASCs informed by BP-26 with like-for-like wheeling costs.
- Methodological assumptions built into all scenarios:
 - No transmission adder
 - No negative benefits
 - Single PFx rate

Scenario Results

#	Scenario	REP Benefits PF/IP/NR loads	Δ from Base	REP Recipients /\$avg/yr		REP Benefits * PF Load Only	Stability
1	Base Case	\$126 million		PacifiCorp PGE	\$81 million \$45 million	\$117 m	Low
2	Removal of Discounting	\$39 million	▼ \$87 million	PacifiCorp	\$39 million	\$27 m	Medium
3	No Conservation Resources in Rate Test	\$53 million	▼ \$73 million	PacifiCorp PGE	\$43 million \$10 million	\$43 m	Medium
4	Combo: Removal of Discounting & No Conservation Resources	Zero	▼ \$126 million	Zero		Zero	High
5	"Exclusive of" All Applicable 7(g) Costs (Conservation) in 7b2 Case, No Conservation Resources in Stack	\$215 million	▲ \$89 million	PacifiCorp PGE	\$128 million \$87 million	\$207 m	Medium
6	Updated Discount Rate (2026 Borrowing Rate Forecast)	\$178 million	▲ \$52 million	PacifiCorp PGE	\$108 million \$70 million	\$169 m	Low
7	<p>November 2025 Settlement Concept</p> <p><i>The Settlement Concept utilizes a weighted distribution of the fixed benefit level to ensure all qualifying utilities receive benefits; this is like the 2012 settlement approach.</i></p> <p><i>Under scenarios 1-6 a single PFx approach is used in lieu of a weighted distribution which creates higher benefit levels but fewer participants.</i></p>	\$157 million	▲ \$31 million	Avista Idaho Northwestern PacifiCorp PGE Puget	\$3 million \$3 million \$3 million \$57 million \$47 million \$44 million	\$148 m	Highest

*In the event NR and IP loads do not materialize, this value approximates REP benefits with PF loads only.

All scenarios are built off the Base Case, which captures assumptions from the 2008 7(b)(2) Methodology referred to as the “Reference Case” while incorporating limited adjustments to align with proposed changes in the ASCM and RPSA as previously discussed.

- 1. Base Case:** reflects Transmission removed from PFX to align with ASCM changes, the Single PFX rate along with capturing the auto-suspension for IOUs with negative benefits in the RPSA.
- 2. Removal of Discounting in the 7(b)(2) Rate Test:** applies a straight average to the 7(b)(2) and Program Case Rates prior to determining the Trigger value.
- 3. No Conservation Resources in Rate Test:** removes conservation as a resource in the Rate Test; this equates to no conservation cost or load adjustments.
- 4. Combo: Removal of Discounting & No Conservation Resources:** This scenario combines scenario 2 and 3
- 5. "Exclusive of" All Applicable 7(g) Costs (Conservation) in 7b2 Case, No Conservation Resources in Stack:** includes the total cost of conservation in the 7(b)(2) Case and removes it as an available resource in the Rate Test.
- 6. Updated Discount Rate:** reflects increase to the discount rate of 1.8% consistent with the latest 2026 Agency forecast for BPA's 30 year borrowing rate.
- 7. November 2025 Settlement Concept:** presented for informational purposes.

1. Base Case

- The Base Case reflects the Transmission adder removed from the PFX rate to align with proposed ASCM changes, includes transitioning to a single PFX rate and capturing the auto-suspension for IOUs with negative benefits in the RPSA.
- Compared to the Reference Case these adjustments generally increase benefit levels.
- REP Benefits are estimated at \$126 million.** In the event NR and IP loads do not materialize, benefits recovered by PF loads is \$117 million.

	Scenario	REP Benefits PF/IP/NR loads	Δ from Base	REP Recipients /\$avg/yr		REP Benefits PF Load Only	Stability
1	Base Case	\$126 million		PacifiCorp PGE	\$81 million \$45 million	\$117 m	Low

2. Removal of Discounting

- This scenario applies a straight average to the 7(b)(2) and Program Case Rates prior to determining the Trigger value.
- Typically, the Program Case rate is materially higher than the 7(b)(2) Case rate. When discounting the larger rate sees a greater reduction. By removing the discounting mechanism, the trigger value increases because the Program Case is not being reduced at a greater rate than the 7(b)(2) Case.
- REP Benefits are estimated at \$39 million.** In the event NR and IP loads do not materialize, benefits recovered by PF loads is \$27 million.

	Scenario	REP Benefits PF/IP/NR loads	Δ from Base	REP Recipients /\$avg/yr		REP Benefits PF Load Only	Stability
1	Base Case	\$126 million		PacifiCorp PGE	\$81 million \$45 million	\$117 m	Low
2	Removal of Discounting	\$39 million	▼ \$87 million	PacifiCorp	\$39 million	\$27 m	Medium

3. No Conservation Resources in Rate Test

- This scenario excludes any conservation resources in the Rate Test; as a result, no conservation cost or load adjustments are incurred.
- In general, exclusion of conservation as a resource and associated costs in the 7(b)(2) Case lowers load obligations without incurring any additional costs putting downward pressure on REP Benefits.
- REP Benefits are estimated at \$53 million.** In the event NR and IP loads do not materialize, benefits recovered by PF loads is \$43 million.

	Scenario	REP Benefits PF/IP/NR loads	Δ from Base	REP Recipients /\$avg/yr		REP Benefits PF Load Only	Stability
1	Base Case	\$126 million		PacifiCorp PGE	\$81 million \$45 million	\$117 m	Low
3	No Conservation Resources in Rate Test	\$53 million	▼ \$73 million	PacifiCorp PGE	\$43 million \$10 million	\$43 m	Medium

4. Combo: Remove Discounting & No Conservation Resources

- This scenario combines scenario 2 and 3. It applies a straight average to the 7(b)(2) and Program Case Rates prior to calculating the trigger and removes conservation as a resource and the associated cost from the Rate Test.
- Removing discounting from the Rate Test reduces benefit levels. In general, exclusion of conservation as a resource and associated costs in the 7(b)(2) Case lowers load obligations without incurring any additional costs putting downward pressure on REP Benefits.
- Combining these two scenarios produces zero REP benefits.**

	Scenario	REP Benefits PF/IP/NR loads	Δ from Base	REP Recipients /\$avg/yr		REP Benefits PF Load Only	Stability
1	Base Case	\$126 million		PacifiCorp PGE	\$81 million \$45 million	\$117 m	Low
4	Combo: Removal Discounting & No Conservation Resources	Zero	▼ \$126 million	Zero		Zero	High

5. “Exclusive of” Applicable 7(g) Cost in 7(b)(2) Case

- For this analysis, the total cost of conservation is identified as a 7(g) cost and included in the 7(b)(2) Case. Conservation is removed an available resource from the resource stack; no load adjustment is made for Conservation.
- This scenario produces higher REP benefits because it increases fixed costs for conservation which is spread across the smaller 7(b)(2) load obligation.
- REP Benefits are estimated at \$215 million.** In the event NR and IP loads do not materialize, benefits recovered by PF loads is \$207 million.

	Scenario	REP Benefits PF/IP/NR loads	Δ from Base	REP Recipients /\$avg/yr		REP Benefits PF Load Only	Stability
1	Base Case	\$126 million		PacifiCorp PGE	\$81 million \$45 million	\$117 m	Low
5	"Exclusive of" All Applicable 7(g) Costs (Conservation) in 7b2 Case, No Conservation Resources in Stack	\$215 million ▲	\$89 million	PacifiCorp PGE	\$128 million \$87 million	\$207 m	Medium

6. Updated Discount Rate

- This scenario captures the Base Case method of discounting and reflects an increase to the discount rate of 1.8% on average consistent with the latest 2026 Agency forecast for BPA's 30 year borrowing rate.
- All else held equal, increasing the discount rate leads to a larger reduction in the Program Case rate compared to the 7(b)(2) Case rate which produces greater REP benefits.
- REP Benefits are estimated at \$178 million.** In the event NR and IP loads do not materialize, benefits recovered by PF loads is \$169 million.

	Scenario	REP Benefits PF/IP/NR loads	Δ from Base	REP Recipients /\$avg/yr		REP Benefits PF Load Only	Stability
1	Base Case	\$126 million		PacifiCorp PGE	\$81 million \$45 million	\$117 m	Low
6	Updated Discount Rate (2026 Borrowing Rate Forecast)	\$178 million ▲	\$52 million	PacifiCorp PGE	\$108 million \$70 million	\$169 m	Low

7. November 2025 Settlement Concept

- The November 2025 Settlement Concept reflected known information at the time.
- The Settlement Concept utilized a weighted distribution of the fixed benefit level computed under the Base Case to ensure all qualifying utilities received benefits; this is like the 2012 Settlement approach with utility specific PFx rates.
- **REP Benefits are estimated at \$157 million.** In the event NR and IP loads do not materialize, benefits recovered by PF loads is \$148 million

	Scenario	REP Benefits PF/IP/NR loads	Δ from Base	REP Recipients /\$avg/yr		REP Benefits PF Load Only	Stability
1	Base Case	\$126 million		PacifiCorp PGE	\$81 million \$45 million	\$117 m	Low
7	November 2025 Settlement Concept	\$157 million ▲	\$31 million	Avista Idaho Northwestern PacifiCorp PGE Puget	\$3 million \$3 million \$3 million \$57 million \$47 million \$44 million	\$148 m	Highest

7(b)(2) LI & IM Process

Settlement Concepts and Opportunities

Richard Greene & Daniel Fisher

Senior Attorney-Advisor VP, NW Requirements Marketing

POST
2028
REP

REP Settlement Concepts

- 2012 REP Settlement was affirmed in *APAC v. BPA*, 733 F.3d 939 (9th Cir. 2013).
- Key findings from that case:
 - **Net Present Value.** BPA can “test” REP benefits using long-term forecasts, and net-present values. So long as NPV is *less* than what IOUs would otherwise be entitled to, lawful. Shape of payments does not matter.
 - **ASC Distributions.** Distribution of REP benefits must align with ASCs and not guarantee any IOU a payment. BPA did this through its PFX threshold test, followed by its multiple PFX rate approach.
 - **Multiple PFX Rates.** BPA can develop multiple PFX rates to spread fixed benefits more broadly among IOUs.
 - **Waiver of *in lieu*.** Waiver of certain REP cost-saving features of the Act (Section 5(c)(5) *in lieu*) is permissible.

Timelines and Opportunities

- Section 7(b)(2) LI/IM 7(i) process will commence around **December 14, 2026**.
 - Between now and then, BPA Staff will be preparing the Initial Proposal for the Section 7(b)(2) LI/IM Section 7(i) process.
 - No other workshops are planned.
 - BPA Staff's position on LI and IM will be presented in the Initial Proposal filed with the commencement of the Section 7(i).
- Until then, stakeholders have an opportunity to discuss settlement.
 - BPA Staff remain available to support these efforts so long as it does not interfere with Staff's preparations for the Initial Proposal.
 - BPA Staff would appreciate an update on settlement talks by **November 13**.
- If Settlement is reached, BPA Staff would pivot 7(i) to a Settlement process consistent with approach used in 2012 REP Settlement.

7(b)(2) LI & IM Process

Close-out of Morning

Daniel Fisher

Vice President, NW Requirements Marketing

Transition to Technical Modeling

- This concludes the background portion of the workshop. For technical modeling and a deeper dive into RAM, please join us after the lunch break.
- Submit written comments and questions to rep2028@bpa.gov.
- Details to attend all Post-2028 REP Phase 2 workshop can be found on [BPA's event calendar](#).
- For REP background, Post-2028 public workshop materials, public notices, and additional REP resources, go to the [Post-2028 REP webpage](#).
- To receive pertinent notifications related to this process sign up for [Tech Forum](#).

7(b)(2) LI & IM Process

Appendix

Definitions / Key terms

- **Unbifurcated PF Rate:** initial rate with costs shared by PF public and exchange loads (PF rate assuming 7(b)(2) test does not trigger).
- **Program Case Rate:** actual rates under the NWPA, excluding certain 7(g) costs.
- **7(b)(2) Case Rate:** hypothetical rate with certain NWPA provisions removed.
- **Applicable 7(g) costs:** conservation costs, experimental resource costs, and uncontrollable events.
- **Resource Stack:** a hypothetical set of resources to serve 7(b)(2) case loads if the Federal Base System were fully exhausted.

Transmission in ASCs and the PFx Rate

- The primary change to ASCs in the modeling is the inclusion of “like-for-like transmission” costs. BPA staff understand that the ASCM process has not concluded and there is not a final decision regarding this aspect of the ASC, therefore this assumption is a place-holder and does not reflect any certainty in a final decision.
- No “Transmission Adder” for the PFx rate in RAM. When ASCs are assumed to include all transmission costs, RAM has a feature that partially offsets those costs with BPA’s costs of transmission. Under the assumption of like-for-like transmission costs (pre-decisional) between Exchanging ASCs and BPA, the transmission adder in RAM was removed.

No Negative Benefits

- No exchanging participants with negative benefits.
 - The 2026 RPSA includes language regarding suspension and termination of participation in the exchange when participants' benefits go negative.
 - The current modeling assumes that when an IOU reflects negative benefits, they are removed from that particular rate case's calculations and RAM is then re-run with the remaining IOUs.
 - This process continues until there are no IOUs showing negative benefits.

Single PFX Rate

- Under the 2012 Settlement, RAM calculated utility-specific PFX rates. BPA's proposal for the Post-2028 REP is to use a single PFX rate in RAM.
- While using a single or multiple PFX rate does result in the same total benefit levels for the aggregate whole, the multiple PFX rates method breaks down when several of the IOUs are projected to have negative benefits and therefore are excluded from the exchange.
- Due to the proposed change above of “no negative benefits”, staff have also assumed a single PFX rate for the 7(b)(2) test. This typically results in higher benefit levels; however, those benefits are distributed among fewer IOUs.