Technical Appendix A: Global Assumptions

Contents

Introduction

Early in the power planning process, the Council defines a set of assumptions that are used across different elements of the analysis. This technical appendix provides details around many of the global assumptions used in the Ninth Power Plan modeling.

In addition to the information presented in this appendix, the following technical appendices also detail assumptions that are used across many elements of the analysis:

- Technical Appendix B – Existing System Parameters and Policies
- Technical Appendix C – Methodology for Quantifiable Environmental Costs and Benefits
- Technical Appendix D – Climate Model Data and Assumptions

Analysis Period

Under the Northwest Power Act, the Council's Power Plan is to put forth a scheme for new resources, including demand-side resources such as conservation, to reduce or meet the Bonneville Power Administration's obligation.[1] In addition, the Council is to include "a demand forecast of at least twenty years."[2] This has resulted in the Council typically analyzing a 20-year period for power planning, as the long-term demand forecast is useful for informing near-term resource decisions.

At the start of every power plan process, the Council decides on the 20-year analytical period to align all data and modeling assumptions. Given the prevalence of hydropower in the region, much of the Council's modeling is done in terms of a "water year," which is defined as the period of October 1 through September 30. For the Ninth Power Plan, the 20-year period is represented by October 2026 through September 2046. Translating this into calendar terms, this essentially represents 2027-2046.

While the Council analyzes 20 years into the future, the focus of recommendations is for the near-term action plan period. This is defined as the first six years of the power planning horizon: October 2026 through September 2032 (or 2027-2032).

Economic and Financial Assumptions

The Council's power planning process involves several analytical steps including projecting future demand for electricity, estimating the quantities and costs of new resources, and simulating operations of the power system to meet future needs with those new resources. Each of these steps requires assumptions around financial and economic variables. It is critical to align these assumptions to ensure that comparisons are made on an apples-to-apples basis. This section details the assumptions the Council used in the Ninth Power Plan to align financial assumptions.

Dollar Year and Adjustment Factors

The Ninth Power Plan assumes a base dollar year of 2024 for all financial assumptions. This ensures consistency in the treatment of cost assumptions throughout the analysis. The Council uses consumer price index (CPI) deflators data assumptions from S&P Global Market Intelligence to consistently adjust to 2024 dollars across planning assumptions.

Discount Rate

As the power plan analysis covers a 20-year horizon, the Council uses a discount rate to account for the time preference of money. To understand the concept of time preference, consider the general observation that people, given the choice, would prefer to consume now rather than later. This time

[1] Northwest Power Act, §4(e)(2), 94 Stat. 2706.
[2] Northwest Power Act, §4(e)(3)(D), 97 Stat. 2706.

preference is also related to market interest rates. Essentially, the idea is that a dollar paid next year is less of a burden than a dollar today because that dollar could be invested and, assuming a sufficient rate of return, the proceeds from that return could be used to pay the dollar cost in the future year. Using a discount rate allows the Council to translate costs incurred at different times into comparable present values, enabling a fairer comparison of the new resource options considered in the plan.

To take an example, there are some resources that have high upfront costs with low variable or operating costs. This could include resource options like solar, wind, and conservation. The costs are predominantly incurred at the beginning of resource development, with little to no ongoing maintenance costs. On the other hand, there are resource options that have costs that incur both at the beginning, as well as ongoing variable and fixed costs from maintenance and fuel. An example would be a natural gas turbine. These two cost streams would vary depending on the time preference. If costs today were valued the same as costs in the future (i.e. a 0% discount rate), a resource that has higher upfront costs, but lower long-term costs would look relatively cheaper than the alternative. Alternatively, a higher discount rate reduces the importance of future costs compared to today, causing those resources with higher ongoing costs to look relatively cheaper.

For the Ninth Power Plan, the Council used Northwest utility discount rates and created a blended approach based on a sales-weighted average for those utilities. This included data from all the investor-owned utilities in the region, Bonneville Power Administration, and Tacoma Power.[3] This resulted in a discount rate of 3.7%.[4]

Staff conducted a sensitivity on the discount rate using Aurora, the Council's West-wide capital expansion model. For this sensitivity, staff used both the sales-weighted 3.7% discount rate and the Bonneville Power Administration's 2.8% discount rate in a West-wide market study. The result showed negligible difference in Northwest builds, suggesting that a 1% difference in discount rate is not going to drive significantly different resource decisions in the region (rather, other factors are likely driving those resource decisions).

Financing Assumptions

Determining the present value cost of any resource requires additional considerations around who pays for the resource. These assumptions vary by resource.

Demand-Side Resources

For demand response, the only financing assumption used to determine present value costs is the discount rate, as described earlier.

[3] The Council also received data from Grant PUD and Clark PUD, both of which assumed the Council's discount rate from the 2021 Power Plan. Since these were developed from prior Council work (using a similar methodology), staff decided to exclude these from the sales-weighted approach.

[4] This workbook outlines the discount rate analysis: https://nwcouncil.box.com/v/ninthplandiscountrate.

For conservation and rooftop solar, the underlying assumptions of sponsor costs rely on the same data set as used to create the discount rate, namely utility data. For these resources, the Council also includes assumptions regarding who pays for the cost (e.g. customer vs utility) and the portion of the cost paid for by each entity (e.g. initial capital cost, administrative cost, maintenance costs, etc.). For the consumer portion of the sponsor costs, the Council used information from the Federal Reserve's Survey of Consumer Finances data.[5]

One notable change for the Ninth Plan is the assumption around who pays for the upfront capital cost of the measure. In previous power plans, the Council assumed that some portion of this cost for conservation was paid for by consumers. The Council changed this approach for the Ninth Plan to assume the utility pays the full cost of conservation, consistent with the treatment of all other resources considered in the analysis. The Ninth Plan continues to assume that consumers pay for the ongoing annual operations and maintenance (O&M) costs associated with the resource.

The financial assumptions used to calculate present value vary by sector, primarily driven by difference in the assumed administrative costs. The tables below provide the final assumptions as used in the Council's ProCost tool, which calculates the levelized cost[6] of conservation and rooftop solar resources.

Table A - 1: Residential Sector Financial Input Assumptions

Sponsor Parameters	Customer	Bonneville	Retail Electric Utility
Real After-Tax Cost of Capital[7]	4.2%	2.81%	4.10%
Financial Life (years)	0	0	0
Sponsor Share of Initial Capital Cost	0%	40%	60%
Sponsor Share of Annual O&M	100%	0%	0%
Sponsor Share of Administrative Costs	0%	20%	80%
Residential Admin Cost per kWh	$0.16		

[5] These data were captured in a Department of Energy 2022 Technical Support Document for Furnace Fans. The specific data are from Table 8.3.7 in the TSD, available here: https://www.regulations.gov/document/EERE-2021-BT-STD-0029-0014.

[6] The levelized cost of a resource is the present value of the lifetime cost of the resource, allowing for a comparison of resources with different lifetimes and other attributes to be compared on a cost basis.

[7] The real after-tax cost of capital refers to the final cost of an expense after all applicable taxes and tax benefits are accounted for, adjusted for inflation.

Table A - 2: Commercial Sector Financial Input Assumptions

Sponsor Parameters	Customer	Bonneville	Retail Electric Utility
Real After-Tax Cost of Capital	5.2%	2.81%	4.10%
Financial Life (years)	0	0	0
Sponsor Share of Initial Capital Cost	0%	40%	60%
Sponsor Share of Annual O&M	100%	0%	0%
Sponsor Share of Administrative Costs	0%	20%	80%
Residential Admin Cost per kWh	$0.13		

Table A - 3: Industrial Sector Financial Input Assumptions

Sponsor Parameters	Customer	Bonneville	Retail Electric Utility
Real After-Tax Cost of Capital	5.8%	2.81%	4.10%
Financial Life (years)	0	0	0
Sponsor Share of Initial Capital Cost	0%	40%	60%
Sponsor Share of Annual O&M	100%	0%	0%
Sponsor Share of Administrative Costs	0%	20%	80%
Residential Admin Cost per kWh	$0.06		

Table A - 4: Agricultural Sector Financial Assumptions

Sponsor Parameters	Customer	Bonneville	Retail Electric Utility
Real After-Tax Cost of Capital	4.9%	2.81%	4.10%
Financial Life (years)	0	0	0
Sponsor Share of Initial Capital Cost	0%	40%	60%
Sponsor Share of Annual O&M	100%	0%	0%
Sponsor Share of Administrative Costs	0%	20%	80%
Residential Admin Cost per kWh	$0.12		

Table A - 5: Utility System Financial Assumptions

Sponsor Parameters	Customer	Bonneville	Retail Electric Utility
Real After-Tax Cost of Capital	3.8%	2.81%	4.10%
Financial Life (years)	0	0	0
Sponsor Share of Initial Capital Cost	0%	40%	60%
Sponsor Share of Annual O&M	100%	0%	0%
Sponsor Share of Administrative Costs	0%	20%	80%
Residential Admin Cost per kWh	$0.12		

More information on how financial input assumptions are used in demand side resources are available in Technical Appendices H, I, and J, covering conservation, demand response, and rooftop solar, respectively.

Supply-Side Resources

For generating resources, financing assumptions also include assumptions regarding tax rates, insurance, debt, and return on equity. Assumptions related to debt and return on equity are then weighted based on sponsor share, assuming 60% utility and 40% merchant/independent power producer. All financing assumptions, including the debt and equity ratings are informed by the U.S. Environmental Protection Agency's assumptions for power sector modeling.[8] Table A - 6 provides the generating resource financing assumptions assumed in the Ninth Power Plan.

[8] Documentation of financing assumptions for EPA's power sector modeling are available here: https://www.epa.gov/system/files/documents/2021-09/chapter-10-financial-assumptions.pdf.

Table A - 6: Utility Scale Generating Resource Financing Assumptions

Parameters	Ninth Plan Assumption		
Federal income tax rate	21%		
State income tax rate	6.45%		
Property tax	0.9%		
Insurance	0.3%		
	Utility	**Merchant/IPP**	**9P Assumption**
Debt fraction	50/50	55/45	52/48
Debt interest rate (nominal)	3.5%	6.27%	4.61%
Return on equity (nominal)	7.17%	9.74%	8.20%

More information on the financial assumptions of supply-side resources is available in Technical Appendix G – New Generating Resources.

Approach to Consistent Treatment of New Resource Costs

The Power Act directs the Council to develop a power plan that gives priority to resources that are cost-effective.[9] Cost-effective means that such resources or conservation measures are forecast to be reliable and available within the time it is needed. The resources also must "meet or reduce the electric power demand ... at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource, or any combination thereof."[10] Therefore, a resource is only cost-effective in comparison to other measures or resources (or combination of resources), and it is the incremental system cost that provides a basis for comparison between resources.

To support this comparison, the Council works to ensure that all new measures and resources are assessed on even footing. Key to this, is a consistent treatment of costs for new resource options. Early in the power plan process, the Council developed a framework for the consistent treatment of costs, connecting each element back to its underpinning in the Power Act.

Core to the bulk of the cost comparison between resources is the definition of system cost in the Power Act:

[9] Northwest Power Act, §4(e)(1), 97 Stat. 2706
[10] Northwest Power Act, §3(4)(A), 97 Stat. 2706.

> "… an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, the cost of distribution and transmission to the consumer and, among other factors, waste disposal costs, end-of-cycle costs, and fuel costs (including projected increases), and such quantifiable environmental costs and benefits as the Administrator determines, on the basis of a methodology developed by the Council as part of the plan, or in the absence of the plan by the Administrator, are directly attributable to such measure or resource."[11]

In addition to system cost, the Council also considers other elements of costs that connect to directives of the Power Act, including a 10% preference adder for conservation[12] and the importance of adequacy and reliability[13].

To account for all these elements together, the Council created a resource cost framework that identifies costs to consider for a measure and how that cost is treated across resources.[14] The Council uses a "total cost" perspective to reflect resource costs, regardless of who pays for those costs. The goal of the framework is to provide consistency (or symmetry) in treatment of costs across all resources. The Council recognizes, however, that consistency is not required under the statute, nor is it always possible or appropriate across resources. Not all direct costs and benefits of a measure or resource are quantifiable, nor are all costs equally applicable as the statute acknowledges may be the case in the definition of system costs. Additionally, especially when considering quantifiable environmental costs and benefits, the Council takes care to not double count the quantified effect as both a cost for one resource and a benefit for another resource.[15]

For the Ninth Power Plan, the Council updated two areas for cost treatment: treatment of state tax credits and valuing resiliency for buildings provided by certain resources. Regarding state tax credits, the Council historically has treated those as in-region transfer payments, essentially ignoring them for the purposes of developing resource costs. For the purposes of the Ninth Power Plan, the Council shifted this approach to recognize that the funding to support state tax credits represents a range of sources outside of ratepayer funds, including federal dollars flowing to the states. Therefore, the Council decided to apply state tax credits as a reduction to the total cost, where applicable.

The Council's 2021 Power Plan identified that some resources, specifically conservation resources, could provide resiliency benefits for buildings. This was highlighted after events like the Texas freeze in 2021 which identified the importance of building resilience when the power is out. Since the 2021 Power Plan, the Council's Regional Technical Forum (RTF) developed a methodology for determining a quantifiable benefit for resiliency of buildings for resources that provide value when the system is

[11] Northwest Power Act, §3(4)(B), 97 Stat. 2706
[12] Northwest Power Act, §3(4)(D), 97 Stat. 2706
[13] Northwest Power Act, §2(2), 97 Stat. 2706
[14] This decisions on cost treatment for the Ninth Power Plan have been captured in the Council's Quantifiable Resource Cost Framework document: https://nwcouncil.box.com/v/ninthplancostframework.
[15] More information on the Council's treatment of quantifiable environmental costs and benefits is available in Technical Appendix C: Methodology for Quantifiable Environmental Costs and Benefits.

down. This work is available on the RTF website.[16] The values are $0.0018/kWh for gas-heated homes, $0.0062 for heat pump heated homes, and $0.0078 for electric resistance heated homes and were applied to weatherization measures for conservation.

More information on cost assumptions for resources is available in Technical Appendices G, H, I, and J, covering new generating resources, conservation, demand response, and rooftop solar, respectively.

Approach to Social Cost of Carbon

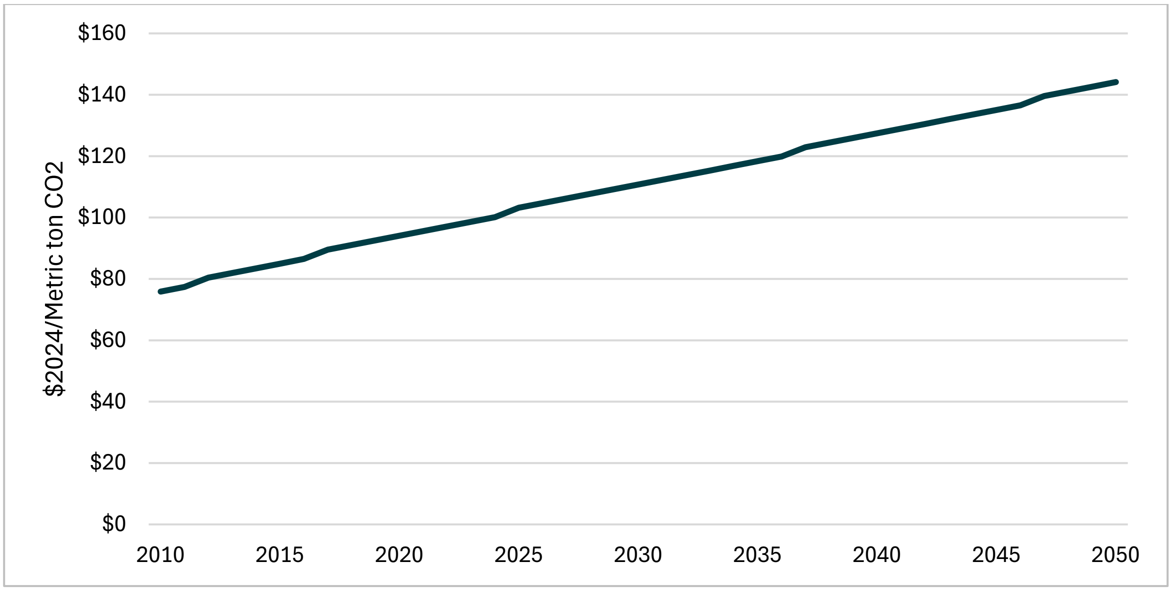
The social cost of carbon (SCC) is an estimate, in dollars, of the global damages from a ton of carbon dioxide. The Council has used the SCC in various ways in its power planning to monetize environmental impacts from carbon and other emissions. For the Ninth Power Plan, the Council is using the SCC where required by specific jurisdictions.

The Council kicked off its official power plan review in February 2025. At this time, the Trump Administration updated federal guidance and requirements to remove the use of the SCC for planning. Given this federal guidance, rather than applying the SCC to resource decisions for the full region, the Council opted for a different approach for the Ninth Power Plan. The Council will apply the SCC only where required by specific jurisdictions. At the time of power plan development, Washington state was the only jurisdiction in the region requiring the use of the SCC in resource decisions.

In May 2019, Washington's Governor Inslee signed into law the Clean Energy Transformation Act (CETA). This legislation places many requirements on utilities, as the state moves towards a greenhouse-gas-emission-free electricity system by 2045. One of these requirements is for electric utilities to "… consider the social cost of greenhouse gas emissions … when developing integrated resource plans and clean energy action plans."[17] CETA goes on further to require electric utilities to use the SCC as a cost-adder when evaluating conservation and developing integrated resource plans. The specific value for the SCC required by CETA is determined by the Interagency Working Group on SCC using a 2.5% discount rate.[18] The specific assumptions for SCC are shown in Figure A - 1.

[16] https://rtf.nwcouncil.org/other/energy-efficiency-resilience-valuation-methodology-study.
[17] Washington CETA, SB 5119, 2019, § 14(3).
[18] Washington CETA, SB 5119, 2019, § 15. This specifically points to Table 2 under the Technical Support Document published under Executive Order No. 12866 on August 16. The Technical Support Document is available here: https://www.epa.gov/sites/default/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.

Figure A - 1: Social Cost of Carbon Values[19]



To implement this approach, the Council ultimately relied on carbon pricing for Washington. In 2021, Washington passed the Climate Commitment Act.[20] This legislation established a cap-and-invest program creating carbon pricing in the state. The Council used these carbon prices as a proxy for planning with a SCC, but just for the state of Washington. While the carbon prices are not equivalent to the SCC values required by CETA, the prices provide a reasonable proxy and the approach aligns well with the capabilities of the Council's modeling suite.[21]

Transmission and Distribution Considerations for Resources

In the Council's modeling suite, loads and resources are compared at a common point of generation busbar. For the Ninth Power Plan, this analysis is done within 17 zones for the region. Within the models, this zonal approach allows for some analysis on the locational value of resources based on transmission development, but it does not provide any insight on the relative value of resources within zones. To allow for apples-to-apples comparison of resources, while also accounting for transmission and distribution considerations not directly modeled, the Council must develop common assumptions around transmission and distribution system characteristics as part of new resource development. This section outlines those assumptions.

[19] More details behind these values is available here: https://nwcouncil.box.com/s/26txw1xs904xr0pw89rbhgcmn8kdjvjv.
[20] More information on the Climate Commitment Act is available on the Washington State Legislatures' website: https://app.leg.wa.gov/billsummary?billnumber=5126&year=2021.
[21] More information on the Council's modeling framework is available in Technical Appendix K: Modeling Framework.

Line Loss Assumptions for Demand-Side Resources

As part of comparing resources to a common point of generation busbar, demand-side resources (conservation, demand response, and rooftop solar) are grossed up to account for line losses that would have occurred had a generating resource produced the power saved. In other words, the Council takes the savings assumed at the site of delivery and adds to it additional savings to represent the line losses from moving energy from generation to load. For the Ninth Power Plan, the Council updated its assumption of line losses for demand-side resources. The Council contracted with GDS Associates who obtained average line loss data from 56 utilities representing 83% of the regional load. These data were then weighted (using system load for transmission loss weighting and utility size information for distribution loss weighting) to determine the final average line loss assumptions for the plan as shown in **Error! Reference source not found.**Table A - 7. More background and details on the approach are provided in the materials presented at the September 24, 2024[22] and November 6, 2024[23] Conservation Resources Advisory Committee meetings.

Table A - 7: Ninth Plan Line Loss Assumptions

Loss	Assumption
Transmission	2.8%
Distribution	4.4%
Total	7.2%

Transmission and Distribution Deferral Values

Certain resources can defer investment in transmission and/or distribution systems. While the Council's modeling will assess the locational value of resources across 17 zones, and therefore the value of deferring large, interzone transmission development, the models will not assess this value within zones. Instead, the Council develops transmission and distribution deferral values to capture this system benefit for the relevant resource options, such as conservation. This value is included in the costs of relevant resources.

For the 2021 Power Plan, the Council updated its approach to estimating transmission and distribution deferral values. After reviewing many of the methodologies across the region, the Council (with input from regional experts) chose to use PacifiCorp's methodology for determining these deferral values. The Council collected data from five utilities and load-weighted the results for a single regional value for use in the power plan.

[22] https://www.nwcouncil.org/calendar/conservation-resources-advisory-committee-2024-09-24.
[23] https://www.nwcouncil.org/calendar/conservation-resources-advisory-committee-2024-11-06.

For the Ninth Power Plan, the Council built on this approach by using a similar survey instrument to collect data from utilities. In addition, the Council collected data from integrated resource plans, conservation potential assessment, and other documents. Because of the zonal modeling approach, staff focused on collecting data that represented the value of transmission deferral within a zone. This resulted in data from 11 regional utilities. Of these utilities, four of them pointed to the Council's assumptions for the 2021 Power Plan. Staff decided to remove these from the analysis, leaving the data from the remaining seven utilities. The data showed significant differences across the region, particularly between utilities on the west side of the Cascades verses those on the east. Since there wasn't sufficient data to develop a value per zone, while also recognizing the difference across the region, the Council developed a "West" value and an "East" value. Additionally, the Council developed a "Regional" value to be used for the two zones that represent the Bonneville regions crossing the east/west divide.[24] The final values for the Ninth Plan are shown in Table A - 8.[25]

Table A - 8: Transmission and Distribution Values for the Ninth Power Plan

Location	Transmission ($2024/ kw-year)	Distribution ($2024/ kw-year)	Combined ($2024/ kw-year)
West	$14.69	$24.18	$38.87
East	$4.77	$11.71	$16.48
Regional	$11.13	$19.71	$30.85

Modeling Zones

The Ninth Plan is the Council's first to represent the region in multiple modeling zones across all its tools. The modeling zones are based roughly on balancing authorities, but they are not intended to precisely reflect any single balancing authority. For the Council's demand forecast, the Council modeled 13 zones tied to the balancing authorities in the region (see Technical Appendix F). For the scenario modeling, the Council used 17 zones. These 17 zones generally reflect the balancing authorities, but split out the Bonneville and Puget Sound areas into more granular zones. This scenario modeling includes the zonal set up for GENESYS (the Council's adequacy tool), Aurora (the Council's tool for the west-wide market study), and OptGen/SDDP (the Council's regional capacity expansion model). More information on this modeling suite is available in Technical Appendix K – Modeling Framework. Discussion of how the Council leveraged the zonal information in the development of

[24] The Council's models use three different zones to represent the Bonneville balancing area: Bonneville OR, Bonneville WA, and Bonneville ID/MT. For the purposes of the transmission and distribution deferral values, the Council applied the Regional value to the Bonneville OR and Bonneville WA zones and applied the East value to the Bonneville ID/MT zone.

[25] Additional information on the build-up of these assumptions is available here: https://nwcouncil.box.com/v/ninthplant-ddeferral.

resource inputs is available in Technical Appendices G through J. Table A - 9 provides the modeling zones and the modeling abbreviations used throughout the Ninth Plan.

Table A - 9: Modeling Zones for Ninth Plan

Balancing Authority	Load Forecasting Zone	Scenario Modeling Zone
Avista Utilities	AVA	AVA
Bonneville Power Administration	BPA	BPA_IDMT
		BPA_OR
		BPA_WA
Chelan County PUD	CCPUD	CCPUD
Douglas County PUD	DCPUD	DCPUD
Grant County PUD	GCPUD	GCPUD
Idaho Power Company	IPCO	IPCO
NorthWestern Energy	NWMT	NWMT
PacifiCorp, East	PACE	PACE
PacifiCorp, West	PACW	PACW
Portland General Electric	PGE	PGE
Puget Sound Energy	PSE	PSE_Central
		PSE_North
		PSE_Olympia
Seattle City Light	SCL	SCL
Tacoma Power	TPWER	TPWER