2022 INTEGRATED RESOURCE PLAN

Seattle City Light

ACKNOWLEDGEMENTS

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EXECUTIVE SUMMARY

Seattle City Light and partner City of Seattle departments are at an important crossroads along the path to create Seattle's energy future on behalf of the customers and communities we serve. The 2022 Integrated Resource Plan (IRP) is a long-term strategy to meet anticipated customer energy needs over the next 20 years. The IRP also outlines a 10-year clean energy action plan that allows City Light to meet its goals around reliability, affordability, and environmental responsiveness, while also complying with regulatory requirements and ensuring service equity.

The IRP is not meant to prescribe or implement resource-related decisions, but directionally it represents City Light's current view of resource adequacy, Washington state policy requirements, transmission constraints, and available resource technology. As such, it recommends a portfolio composition that would be best positioned to meet those needs.

The recommended 2022 IRP portfolio was selected due to its resource diversity, high customer optionality, low transmission reliance, and reasonable cost. This portfolio of energy resources includes more wind and solar energy serving customer load as well as new customer participation in demand response and energy efficiency. It also paves the way for transportation and building electrification efforts that will shift our communities away from fossil fuels. It recommends that over the next 10 years (2022-2031), City Light will look to add approximately 175 megawatts (MW) of solar and 225 MW of wind to its energy portfolio. In addition, the utility will work with customers to identify around 85 MW of energy efficiency and tailor a demand response shift of up to 47 MW during the summer and around 79 MW for winter. Finally, City Light anticipates around 24 MW of customer-owned solar installations positively impacting our portfolio in the same time frame. The following decade (2032-2041) has similar goals, which are reflected in the Portfolio Analysis discussed later in this document.

The recommendations for the next two years within this biennial IRP update include:

- Continued customer engagement and education about energy efficiency and demand response programs.
- Participation in regional energy programs and markets to reduce load peaks and resource generation fluctuations from localized weather.
- Work with regional partners and planning organizations to identify and start transmission project development processes that expand access to affordable clean power supplies, engaging all stakeholders early in the process.
- Implementation of clean energy supply procurement processes with operational dates as early as the start of 2026 and 2027 for delivery to Seattle.
- Continued climate change and electrification research that will help us refine our resource strategies and timelines.

INTRODUCTION

City Light has provided its customers with reliable, affordable, and environmentally responsive clean energy since 1910. As the utility continues this tradition and plans for the future, it must account for growing power supply demands from its customers, while prioritizing emission reductions. This will ensure an equitable clean energy transition for all customers served.

With shared environmental values, City Light and the residents of Seattle continue to promote balancing power supply demands with environmentally friendly power supply resources required to meet those needs. City Light is a consistent voice for generating electricity with renewable or non-emitting resources and promoting energy efficiency with its customers. It strives to limit negative impacts on the environment and reduce the need for costly new power generation. Since 2005, City Light has operated as greenhouse gas neutral – the first electric utility in the nation to achieve that distinction.

City Light's 2022 Integrated Resource Plan (IRP) outlines how the utility will meet anticipated customer needs under changing market dynamics, evolving policies, and future uncertainties over the next 20 years. The IRP requires a constant review of conditions that affect its power supply needs, costs, and risks. These considerations range from the evaluation of energy efficiency potential and new resource opportunities to ensure reliability, environmental stewardship and compliance with Washington state-mandated clean and renewable resource requirements.

The IRP is created as part of good utility practice and is developed with guidance from the Mayor, City Council, and Washington state law, including the Energy Independence Act (I-937) and the Clean Energy Transformation Act.

The primary goals in developing an integrated resource plan are to:

- Forecast the energy and capacity needed to meet customer demand.
- Determine the utility's capability to supply those needs and ensure flexibility during fluctuation.
- Define the capability and cost of current and prospective resources.
- Evaluate potential future City Light portfolios based on reliability, cost, risk, and environmental impact.
- Recommend a plan of action.

PUBLIC INVOLVEMENT

Over the next 20 years, City Light will track its power supply needs from both new and traditional resources. These power supply choices require investing hundreds of millions of dollars of customer funds and affect future operating costs, reliability, and the City's environmental footprint for decades to come. As a publicly owned utility, customer input on the IRP is essential.

Since fall 2021, City Light has conducted eight external IRP advisory panel meetings that included customers, environmental organizations, regional energy-related governmental organizations, and academic specialists. Presentations included topics such as energy conservation, climate change, load forecasts, resource adequacy, IRP modeling assumptions, and many other energy-related issues. Advisory panel feedback helped to shape the IRP process, findings, and recommendations.

In summarizing the views of the IRP advisory panel and public participants, their commitment to the environment is clear:

- There is broad support for immediate actions to address greenhouse gas emissions that contribute to climate change.
- The focus of a clean energy transformation needs to be equitable, with a priority on helping communities that have been historically impacted by fossil fuel use.
- Planning for more electrification of buildings and transportation in our communities, in conjunction with a changing climate and uncertainty in future transmission availability, remains a top priority.

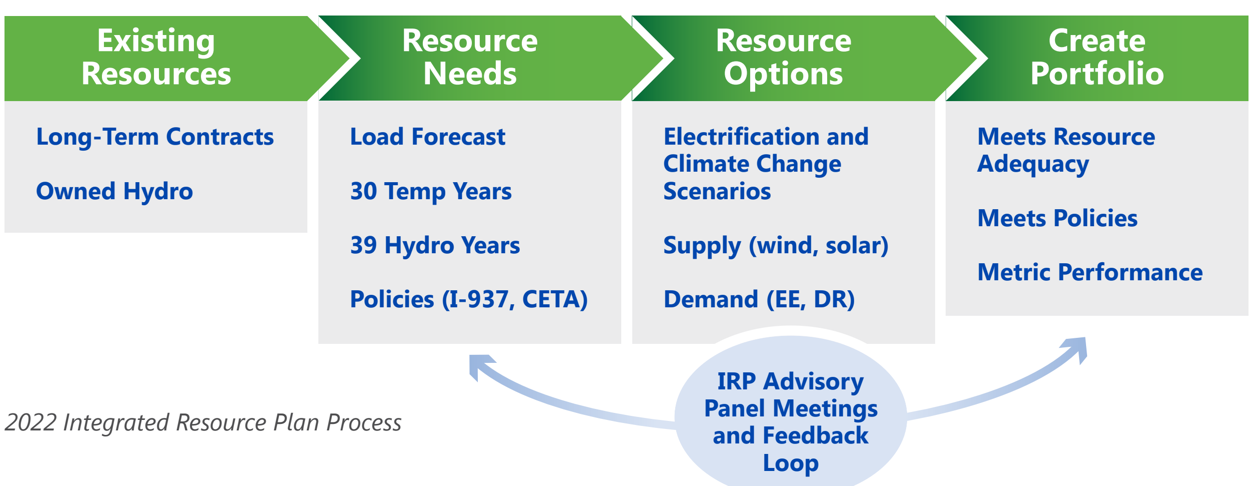
INTEGRATED RESOURCE PLAN PROCESS

The IRP is a long-term decision support tool designed to educate and support stakeholder participation in achieving City Light's energy future. It is also a Washington Utilities and Transportation Commission requirement to develop and update integrated resource plans, make them available to the public every two years, and provide a summary of estimated future resource needs at least 10 years into the future. Consistent with City Light values, the IRP recommendations are balanced to consider how our choices support a healthy environment, stop and reverse inequity, and create a vibrant future for our customers and community. The IRP is one of many important planning processes synchronized into City Light's Strategic Plan.

City Light's IRP process evaluates how robust our choices are at meeting the utility's goals and the range of conditions we expect to experience over the next 20 years. We must consider many different subject areas such as electricity demand forecasting, regional transmission outlooks, supply side renewable resource options and their costs, customer side energy options and their costs, and clean energy policies that City Light must comply with. The utility relies on input from an informed IRP advisory panel composed of external industry experts, individuals advancing equitable and clean energy policies, and City Light experts and leaders from across the utility, as well as City Light's customer outreach processes conducted to support our Strategic Plan and Transportation Electrification Strategic Investment Plan. Guided by this information and Seattle City Council and Mayoral directives, an IRP plan is developed.

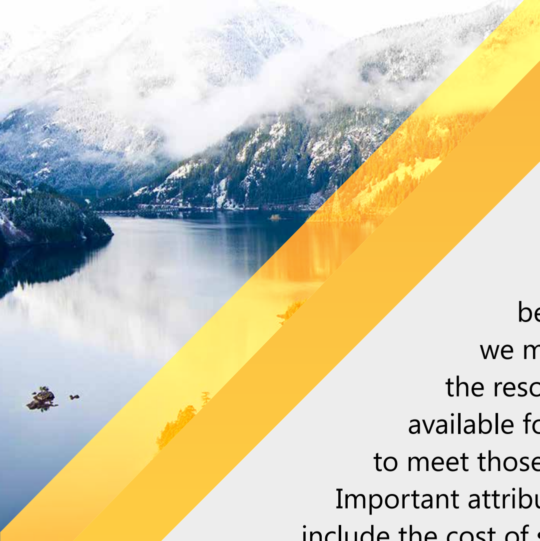
As shown below, the 2022 IRP process starts with City Light's current portfolio of energy contracts and generation and finishes with recommendations needed to meet electricity demands over the next 20 years.

The first stage of the framework, and the IRP starting point, considers City Light's base load forecast, existing resource mix of contracts, and owned generation. The second stage of the framework determines if our existing resource-mix of contracts and generation is on track to meet not only our resource adequacy metric, but also our I-937 and Clean Energy Transformation Act compliance needs. The resource adequacy metric is tested using 39 different water supply conditions, as well as 30 different temperature conditions affecting electricity demand.



2022 Integrated Resource Plan Process

After resource needs have been identified, we must analyze all the resource options available for consideration to meet those resource needs. Important attributes we consider include the cost of supply resources, types (e.g., wind, solar), geographic locations, transmission corridors, and seasonal generation profiles. The same types of attributes are also part of the demand resource options, such as energy efficiency, demand response, and customer solar. In the end, the IRP portfolio selection framework will feature a mix of supply and demand resources that best fit City Light's resource needs.



The City Light IRP portfolio modeling framework develops a mathematically optimized (i.e., minimum cost) portfolio of resources, as shown below.

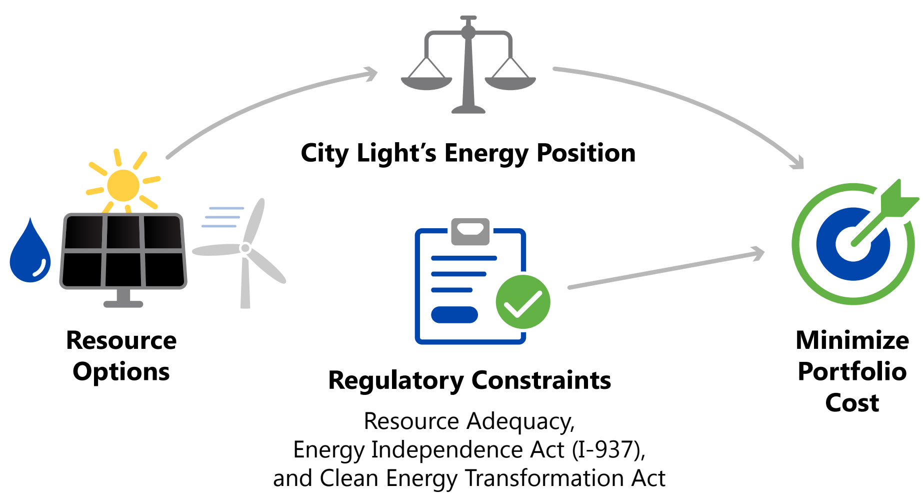
City Light and its stakeholders recognize there are other metrics to consider besides cost when determining the best mix of resources. For the 2022 IRP, City Light ranked and evaluated more than 20 resource strategies to develop a robust plan against six performance metrics:

- Cost
- Greenhouse gas emissions
- Expanded customer programs opportunity
- Transmission risk
- Climate change preparedness
- Electrification preparedness

Each proposed portfolio receives a score and a ranking based on the measured performance, and by process of elimination, a recommended portfolio emerges. The IRP is not meant to prescribe or implement resource-related decisions but is designed to inform long-term and directional plans to best meet City Light's resource needs. City Light will continue to evaluate its IRP resource recommendations at least every two years.

IRP Portfolio Modeling Framework

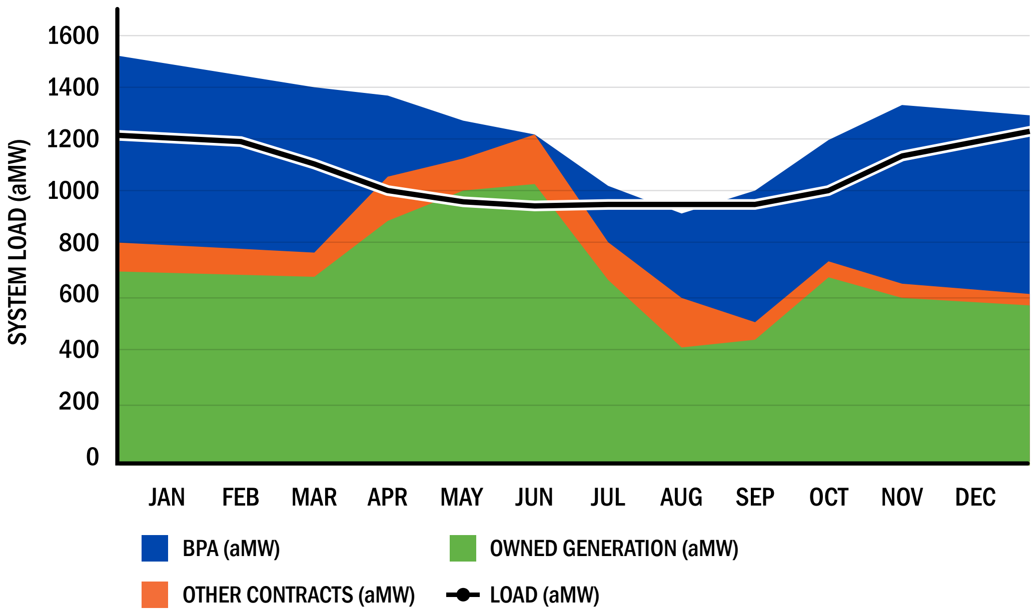
Goal: Design best mix of resources to meet City Light's needs over next 20 years



CURRENT RESOURCE PORTFOLIO

City Light's power resources are typically 90 percent hydropower, approximately half of which is supplied by five hydroelectric projects owned and operated by City Light. Most of the remaining hydropower is purchased from the Bonneville Power Administration (BPA), a nonprofit federal power marketing agency. Beyond generating hydropower, City Light is charged with the responsibility to operate its hydroelectric projects for flood control, fish management, and recreation. City Light's load-resource balance during the calendar year 2022 is shown below.

2022 City Light Load-Resource Balance



Three impactful processes shaping the composition of our future energy portfolio are underway:

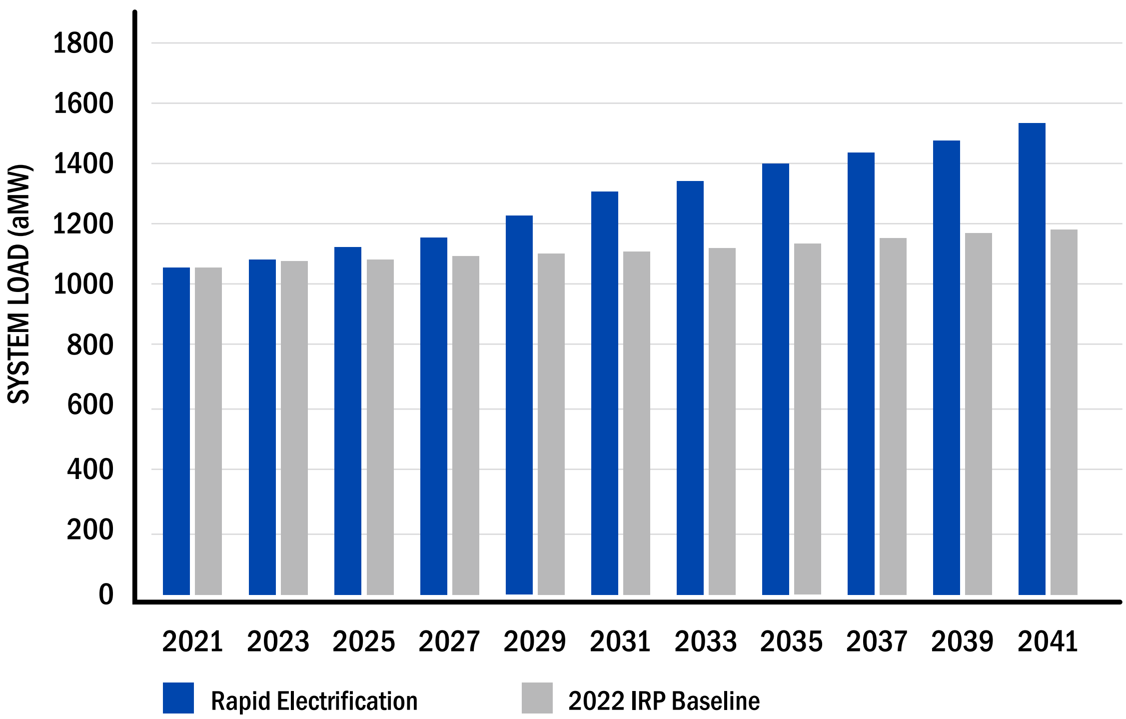
- By 2026, three power purchase contracts/exchanges are set to expire.
- In 2026, City Light hopes to begin operating under a new long-term license for the three dams on the Skagit River.
- In 2028, City Light will begin a new long-term contract with BPA to purchase energy from the federal hydroelectric system. As part of the new contract negotiations, City Light will seek opportunities to improve the timing and magnitude of power deliveries from BPA to best fit our load and resource balance.

LOAD FORECAST

The 2022 IRP baseline scenario anticipated modest load growth of 0.5% per year over the next 10 years. Under the baseline scenario, economic growth and electrification of transportation and buildings contribute to load growth, while market driven energy efficiency and distributed solar generation help mitigate load growth. The baseline load scenario also included variability from a range of different weather conditions to simulate extreme peaking requirements.

In addition to the baseline scenario, the 2022 IRP process also considered separate scenarios that addressed potential load impacts of climate change and more rapid electrification. The rapid electrification scenario was based on City Light and the Electric Power Research Institute's (EPRI) January 2022 Electrification Assessment and served as a "book end" scenario for higher levels of load growth. Under the rapid electrification scenario, City Light's load would increase by 32% compared to the baseline scenario shown below. Impacts to load from climate change were less pronounced. They generally pointed to lower loads in the winter and higher loads in the summer; however, more research is still needed to better model extreme weather conditions and peaking requirements under climate change. Importantly, 2021 featured a new all-time high peak load for June of 1,533 MW, and a near record December peak load of 1,896 MW.

2022 IRP Baseline Load Forecast vs EPRI's Rapid Market Electrification scenarios



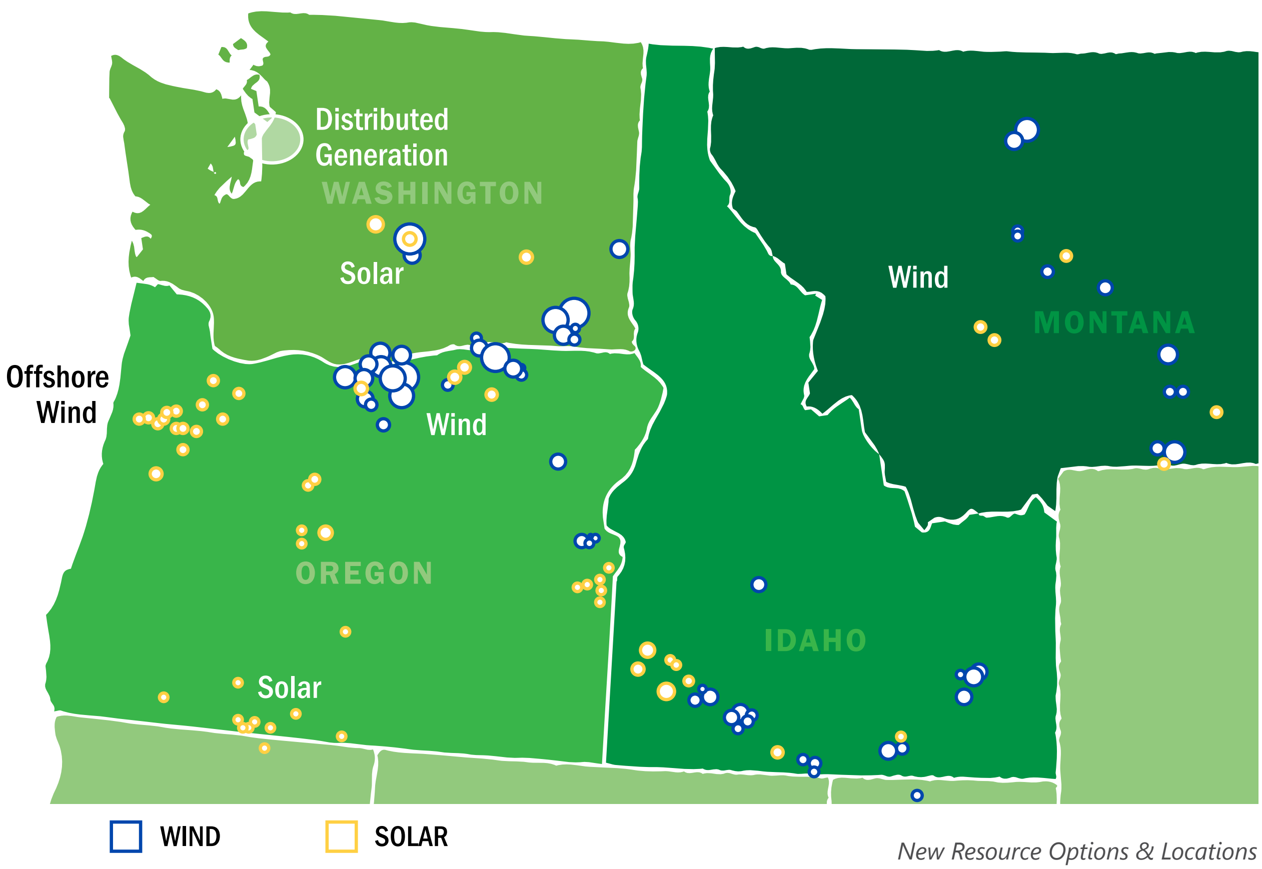
RESOURCE NEEDS

The 2022 IRP features two key conclusions compared to the 2020 IRP Progress Report in terms of City Light's resource needs:

- There are no significant changes in base-scenario summer resource needs compared to the 2020 Progress Report. But the 2022 IRP climate change scenario, which incorporates climate change impacts to weather and local hydrology, clearly shows increasing summer energy shortfalls going forward.
- Winter needs, especially December, are higher than the 2020 IRP progress report indicated, due to the updated load forecast that now features new building electrification codes and additional electric vehicle growth. The Rapid Market Electrification Scenario demonstrates additional significant growth in winter electricity demand.

The 2022 IRP features many of the same utility-scale resource options as the 2020 IRP Progress Report: eastern Washington solar, southeast Oregon solar, and Columbia River Gorge wind. However, the additional electrification and climate change studies informing the 2022 IRP indicate City Light will likely need to pursue acquisition of additional resources, such as:

- Local commercial or community solar projects that will diversify sources of weather-dependent generation and transmission uncertainty, and therefore help mitigate associated risks.
- Offshore and Montana wind in the 2030s with winter peaking generation profiles to help meet expected increases in seasonal demand.
- Demand response programs, which will help the utility manage short-term peaks in electricity demand.



New Resource Options & Locations

REGULATORY REQUIREMENTS

The Clean Energy Transformation (CETA) Act of 2019 recognizes existing hydroelectric projects and nuclear plants as non-emitting greenhouse gas energy generation resources. The three major milestones of CETA are:

1. Utilities must remove coal-fired generation from Washington's allocation of electricity by 2026.
2. Washington retail sales must be greenhouse gas neutral, with at least 80% renewable or non-emitting by 2030.
3. Washington retail sales must be 100% renewable or non-emitting by 2045.

With an existing energy portfolio typically more than 90% renewable or non-emitting, City Light is well positioned for meeting the second CETA milestone listed above.

City Light must comply with the Climate Commitment Act (CCA) of 2021 that requires reductions in greenhouse gas emissions from most sectors of the economy, including the electric utility sector, with milestones beginning in 2023. Entities impacted by these legislative requirements will receive allowances based on their individual emissions from 2015 to 2019; allowances specify the percentage of load that can be served by generation resources that are not provably greenhouse gas free. As of May 2022, the allowance amount is unknown.

The first compliance period is 2023 to 2026. The CCA requires reductions in greenhouse gas emissions to 45% below 1990 levels by 2030 and further reductions to 95% below 1990 levels by 2050. City Light will continue to track rulemaking activities to understand potential impacts to the utility's business and understand how it can manage its future reporting and compliance obligations and the associated costs.

The Energy Independence Act, also known as I-937, requires electric utilities serving at least 25,000 retail customers to use renewable energy and energy conservation. I-937 annual compliance can be met in three ways:

- If a utility has "load growth," each utility shall use eligible renewable resources and/or renewable energy credits (RECs) to meet 15% of its load.
- If a utility has "no load growth," each utility shall use eligible renewable resources and/or RECs to meet 1% of its retail revenue requirement.
- If a utility spends at least 4% of its retail revenue requirement on the incremental cost of renewable energy and/or RECs.

To comply with I-937 requirements, City Light has been using the "no load growth" compliance option since 2019. If City Light has increasing load over four consecutive years, it must meet 15% of sales with eligible resources, RECs, or a combination. Load increased in 2021 compared to 2020, and if load growth continues, City Light will need to take additional actions to ensure compliance with I-937 as early as 2024. With new wind and solar additions potentially starting in 2026, as well as the RECs already committed, City Light is well positioned for meeting I-937 requirements for renewable energy well into the future. After 2030, if City Light has a greenhouse gas free energy portfolio for four years in a row for CETA, then City Light does not have to take any additional actions for I-937.

In 2018, the Mayor and Seattle City Council updated the Seattle Climate Action Plan unveiling the goal to make Seattle carbon neutral (zero net emissions of greenhouse gases) by 2050. Most of the strategic initiatives of this plan involved transportation electrification, building electrification, and energy efficiency.

PORTFOLIO ANALYSIS

As part of the 2022 IRP analysis, three scenarios were considered:

1. Base load (i.e., 2020 corporate load forecast) with historical hydro and historical temperature.
2. Climate change with simulated future hydro and simulated temperature-affected load.
3. EPRI's Rapid Market Electrification with historical hydro and simulated electrification loads.

For planning purposes, the base load and historical hydro scenario were used as the baseline to plan energy portfolios in the 2022 IRP. However, climate change and electrification scenarios were used to better understand if different portfolios had attributes that could help manage uncertain climate change or electrification futures.

City Light developed more than 20 different portfolios of potential additional energy resources and narrowed that to a top seven. These top portfolios aligned with the latest regional transmission assumptions, state and local clean energy policies, resource options, and City Light's resource adequacy metrics.

The 2022 IRP portfolios were evaluated according to six different metrics. These metrics were developed as part of the 2022 IRP process to account for costs (Net Present Value), the climate change scenarios studied (Climate Change impacts), portfolio unspecified purchases (Greenhouse gas emissions), diversity of customer options (Expanded customer programs opportunity), the Rapid Market Electrification scenario studied (Electrification preparedness), and transmission cost and uncertainty (Transmission risk). All these metrics were equally weighted. The top-performing portfolio had the following attributes:

NEW RESOURCE ADDITIONS BY TIME PERIOD	2022–2031	2032–2041	TOTAL
Solar (MW)	175	0	175
Wind (MW)	225	50	275
Energy Efficiency (aMW)	85	31	116
Customer Solar Programs (MW)	24	28	52
Summer Demand Response (MW)	47	31	78
Winter Demand Response (MW)	79	43	122

2022 IRP Recommended Top Portfolio Plan

Columbia River Gorge

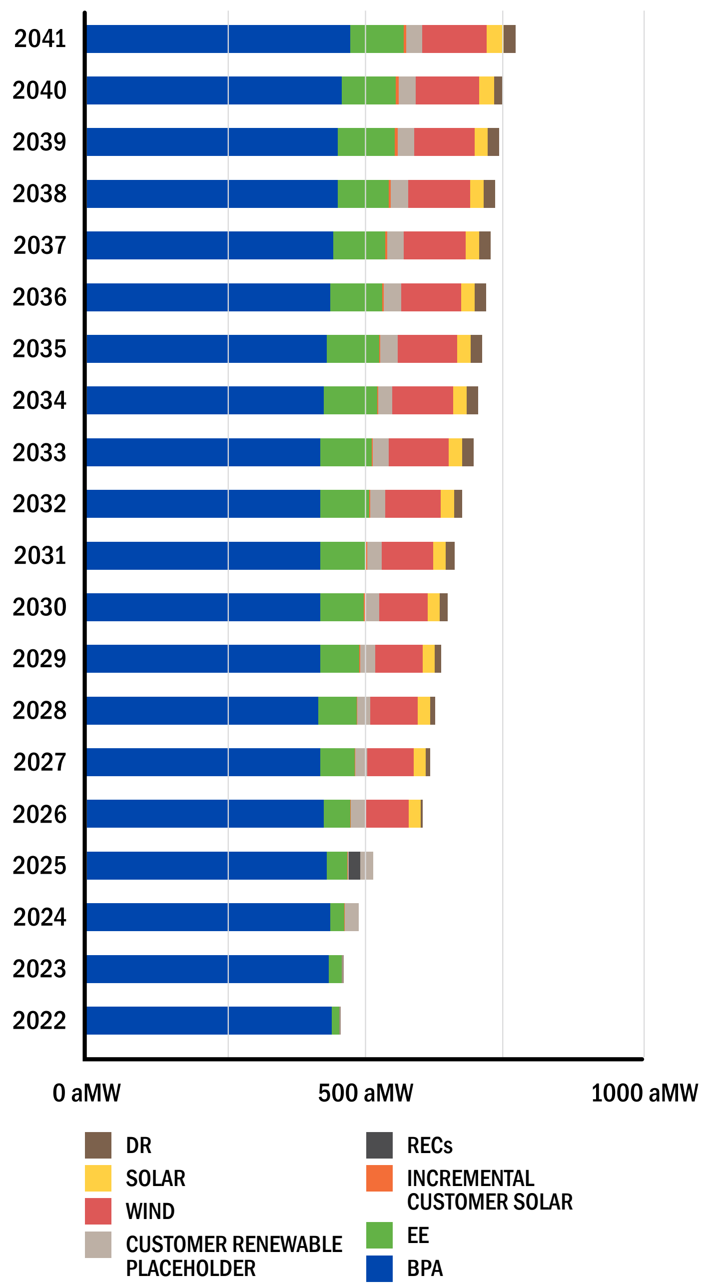
While each successive City Light IRP has its own set of assumptions such as load forecasts, contracted energy, price of new resources, and state policies influencing resource decisions, the 2022 IRP top portfolio contains the largest proportion of solar compared to previous IRPs. Decreasing materials costs and improvements in hardware efficiencies has led to significant decreases in the cost of solar energy over the last several years. However, during spring 2022, prices jumped upward due to supply chain troubles, as well as the U.S. Department of Commerce's review of alleged circumvention of solar panel tariffs in some countries. This investigation could pause manufacturing and shipping of solar panels, and hence delay development of new solar energy projects. Long term, solar energy from eastern Washington or Oregon can provide City Light affordable summer power when the hydroelectric resources run low. Local customer solar can provide non-wired energy solutions with the additional benefit of being strategically deployed to areas of greatest need.

The risk of summer forest fires and heavy smoke in the PNW as our climate changes make wind resources, a continuous theme in City Light's IRP recommended portfolios since 2016, a valuable energy hedge with solar. Wind has also seen price decreases and efficiency increases the last several years. Like solar, wind resources in the Columbia River Gorge also tend to experience peak production during the summer months. Montana wind and offshore wind, both of which can see up to 50% capacity factors, are winter peaking, which will benefit City Light particularly as electrification is expected to increase winter demand. The 2022 IRP recommended portfolio mix (page 13) anticipates all of City Light's wind resources prior to 2030 will be from the Columbia River Gorge area, while after 2030 it is possible that new transmission infrastructure would allow for City Light to benefit from a Montana wind resource. Development of offshore wind technology, such as floating turbines, may also make offshore wind resources off the coast of Washington or Oregon feasible for inclusion in future portfolios.

> *"Decreasing materials costs and improvements in hardware efficiencies has led to significant decreases in the cost of solar energy over the last several years."*

Comparing energy efficiency forecasts between the past few IRPs is much more difficult due to quantifying voluntary technology adoption rates over time, outside of the programmatic adoption rates. The 2022 IRP recommended portfolio includes about 40 average MW (aMW) of energy conservation measures by 2026, which is about 4 aMW higher than the 2022 Conservation Potential Assessment (CPA). The 2022 IRP is the first to recommend a portfolio that endorses demand response programs, as they not only manage climate- or electrification-related extremes, but also generally reduce customers' energy burden. The 2022 IRP top portfolio's resource mix is shown below.

2022 IRP Recommend Top Portfolio Resource Mix



In summary, the new resources outlined in the 2022 integrated resource plan are due to:

- Certain power purchase contracts and exchanges gradually expiring by 2026.
    - o Stateline Wind, Columbia Basin Hydro, Lucky Peak Exchange.
- Clean energy policies forcing coal plant retirements.
    - o 2,150MW coal retirements by 2027 in the Northwest.
    - o Increases regional resource adequacy concerns.
    - o Results in less certainty that City Light can buy affordable and reliable energy in markets.
- Pace of climate change and electrification.
- Increasing customer push for greenhouse gas free portfolio.

There is always the risk of the wind not blowing, the sun not shining, and energy conservation or demand response reaching its limits on helping with resource adequacy. As City Light's electrification loads begin to materialize and we see an increasing frequency of weather extremes associated with climate change, other base load dispatchable resources such as batteries, hydrogen, geothermal, small modular/advanced nuclear, etc., should be part of the discussion to maintain current levels of grid reliability. Given these uncertainties, it is crucial to develop plans in partnership with our customers, community groups and other stakeholders that have the right degree of flexibility to be consistent with their needs and expectations.

CONCLUSIONS

The 2022 IRP helps City Light develop a plan for providing customers with reliable, safe, and affordable clean energy for decades to come. Its core findings are:

- City Light expects modest load growth due to continued electrification of transportation and certain heating and cooling applications in buildings.
- City Light should continue to engage and educate customers about energy efficiency and demand response programs.
- City Light should continue to participate in regional energy programs and markets to increase our ability to meet peaks and ensure uninterrupted service.
- Improvements in the transmission system will be critical to meet clean energy requirements established by city and state legislation. Together with its stakeholders, City Light should continue working with regional partners and planning organizations to identify transmission need and implement transmission development projects. City Light should initiate clean energy supply procurement processes with operational dates as early as 2026 and 2027 for delivery to Seattle.
- City Light should continue climate change and electrification research to refine its resource strategies and timelines.

> *Over the next 10 years, City Light will look to bring many new resources into its portfolio, as well as new licenses and power contracts.*

Over the next 10 years, City Light will look to bring many new resources into its portfolio, as well as new licenses and power contracts. In general, resources will be added proportionally, according to the 2022 IRP Recommended Top Portfolio Plan. Some key milestones over the next 10 years are shown below.

2022 IRP Ten Year Important Milestones

2022	2024	2026	2028	2030	2032
Demand Response Pilot Programs Start (2023)	**Climate Commitment Act 2023**	**~400 MW New Supply Resources Online**	**New BPA Contract Start**	**CETA Greenhouse Gas Neutral**	**Long-Lead Resource Additions MT and Offshore Wind**
Time of Use Rates Pilot	**Opt-in Time of Use Rates Begin**	**~50 aMW Energy Efficiency**	**IRP Progress Report, CPA and Strategic Plan Update**	**Full IRP, CPA, Strategic Plan Update and CEIP**	**~90 aMW Energy Efficiency**
CEIP*	**New ~100 MW Resource for Customer R+**	**New Skagit License Start**	**CEIP Update**		**IRP Progress Report, CPA and Full Strategic Plan Update**
	IRP Progress Report, CPA and Strategic Plan Update**	**~10 MW Demand Response**			**~90 MW Demand Response**
	CEIP Update	**Full IRP, CPA, Full Strategic Plan and CEIP**			**CEIP Update**

**CEIP – Clean Energy Implementation Plan a requirement of the Clean Energy Transformation Act.*
***CPA – Conservation Potential Assessment.*

FUTURE WORK

As negotiations with BPA for the Western Resource Adequacy Program are ongoing, City Light will explore whether its contract could allow for different energy allocation. In other words, the utility should try to structure more energy in December and/or August even as other utilities reach for the same resources. These months will be important as electrification and climate change begin to influence City Light's load and resource balance. Also, the next BPA contract might have options for 100% clean block products. The increasing calls from City Light's customers, as well as the Climate Commitment Act requirements taking effect in 2023, put reductions in resource emissions at a higher priority.

City Light will further study energy efficiency, distributed resources, storage, and customer solar potential under climate change and electrification loads. This will help inform program design to account for future IRP modeling. Future resource options should also consider new, potentially large 24/7 loads such as hydrogen production facilities (200MW-500MW), existing steam plant to electric conversions, or other large base loads. Additional resources and flexibility resulting from grid modernization programs will be important to incorporate into future IRPs as well.

City Light will continue to develop relevant social equity metrics and include these metrics in future IRP analyses and decision processes. Baseline levels for social equity metrics can be established from City Light's current energy portfolio to help identify and prioritize areas for improvement, such as developing energy efficiency, demand response, and community solar programs to ease the energy burden for environmental justice communities and vulnerable populations. Social equity metrics could also be incorporated into IRP portfolios to quantify improvement or detriment to these customers to better inform IRP recommendations.

Incorporation of additional climate change scenarios in IRP analyses will also help to create a more thorough understanding of climate change-induced resource need. BPA recently proposed changes to its regional analysis that now aim to incorporate current and anticipated impacts of climate change on the region. City Light should continue to stay engaged and actively participate in BPA planning activities to help ensure robust and equitable regional energy policy.

APPENDICES

Appendix 1: Current Resource Portfolio

Appendix 2: Load Forecast and Regulatory Impact on Resource Needs

Appendix 3: Resource Options

Appendix 4: Planning for 2022 IRP Baseline & Electrification Portfolio Strategies

Appendix 5: Create Top Portfolio

Appendix 6: Equity, Community Outreach, and Public Involvement Process

Appendix 7: Climate Change

Appendix 8: Resource Adequacy

APPENDIX 1: CURRENT RESOURCE PORTFOLIO

City Light's existing resource portfolio has been cultivated to be among the cleanest and lowest cost in the nation. Energy efficiency programs have contributed to reducing City Light's customer energy use, and currently equate to the addition of several large power plants.

This portfolio includes many past investments in energy efficiency, City Light owned hydropower resources, existing hydropower and renewable contracts from regional partners, and wholesale market purchases.

City Light's power resources are typically 90 percent hydropower, approximately 50 percent of which is supplied by four hydroelectric projects owned and operated by the utility. Most of the remaining hydropower is purchased from the Bonneville Power Administration (BPA), a nonprofit federal power marketing agency. Beyond generating hydropower, City Light has the responsibility to operate its hydroelectric projects for flood control, fish management, and reservoir recreation. Additionally, in coordination with Seattle Public Utilities, two projects are operated for municipal water supply.

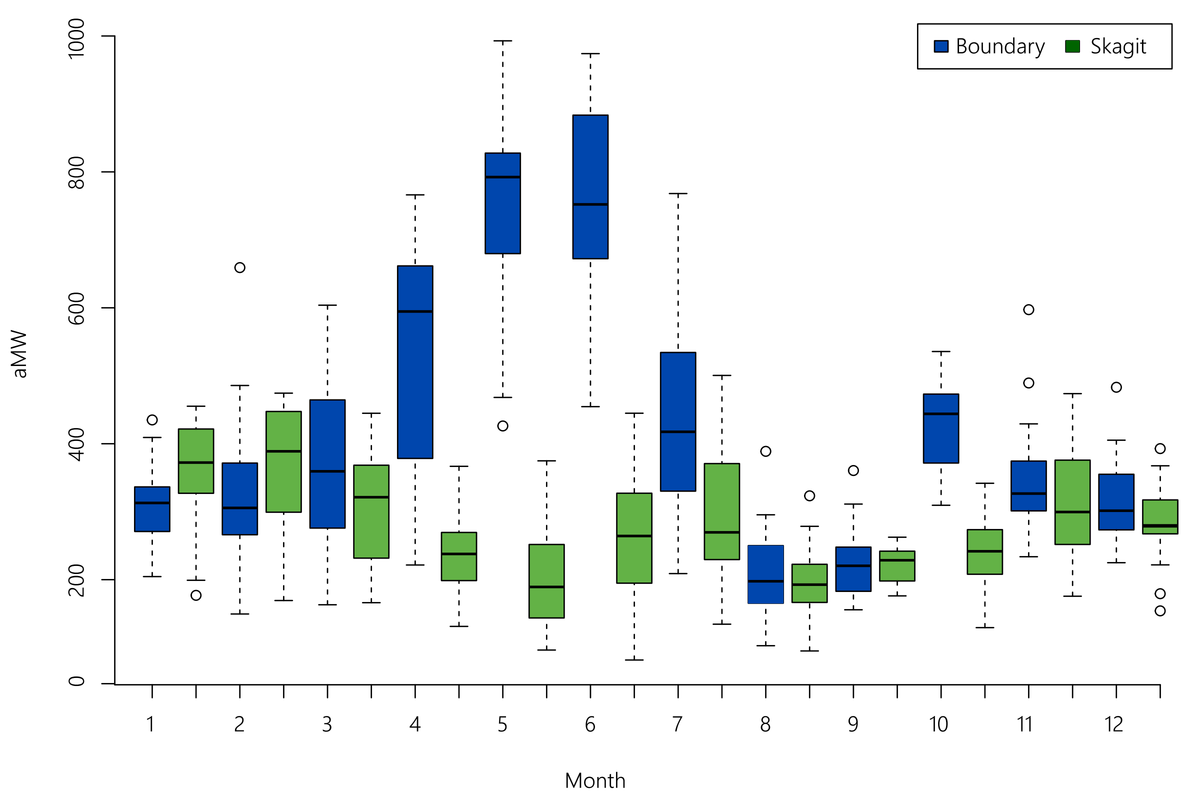
Figure 1 City Light's generation and contracted resources

City Light Owned Generation

Located on the Pend Oreille River in northeastern Washington, Boundary Dam is City Light's largest resource with a peaking capability slightly above 1,000 MW and an average generation of about 438 MW annually. Under the Federal Energy Regulatory Commission (FERC) license, part of Boundary output must be sold to Pend Oreille County Public Utility District No. 1 (PUD) to meet the PUD's load growth. In addition, about five aMW of energy must be delivered to the PUD in compensation for Boundary Dam's encroachment on Box Canyon Dam. While the Boundary Project produces the most power and has substantial operational flexibility, it has only modest storage capacity. Energy from Boundary is delivered to consumers over BPA's transmission grid.

The Skagit Project includes the Ross, Diablo, and Gorge Dams in the North Cascades, which have a combined one-hour peak capability of about 700 MW at full pool. The Skagit Project has generous storage capacity, but also significant operational constraints for fish management. City Light's transmission lines carry the power generation from the Skagit Project to Seattle.

Figure 2 Boundary and Skagit Monthly Generation 2002-2021



Additional power is provided by small hydro projects on the south fork of the Tolt and the Cedar Falls Dam. South Fork Tolt has a one-hour peaking capability of less than 17 MW. Cedar Falls Dam has a capacity of 30 MW. Both projects delivery power via Puget Sound Energy transmission lines.

Figure 3 Cedar Falls and South Fork Tolt Monthly Generation 2002-2021

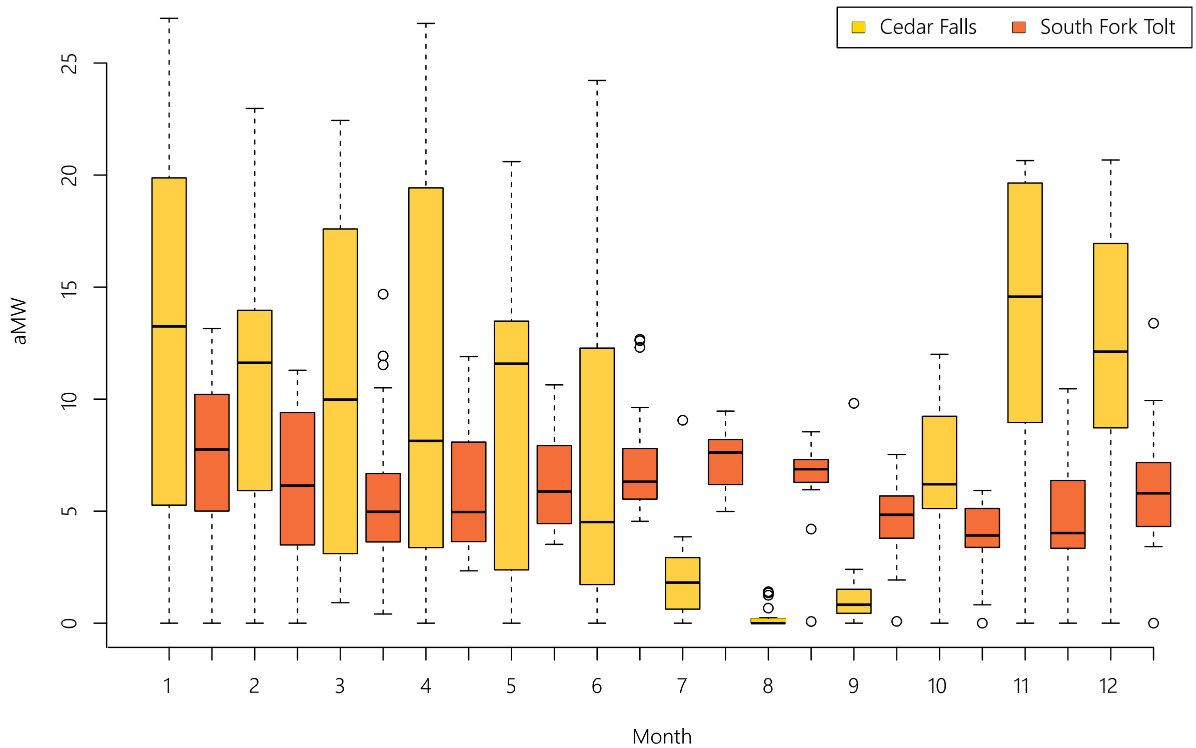


Figure 4 Proportions of City Light's Owned Generation (2002-2021)

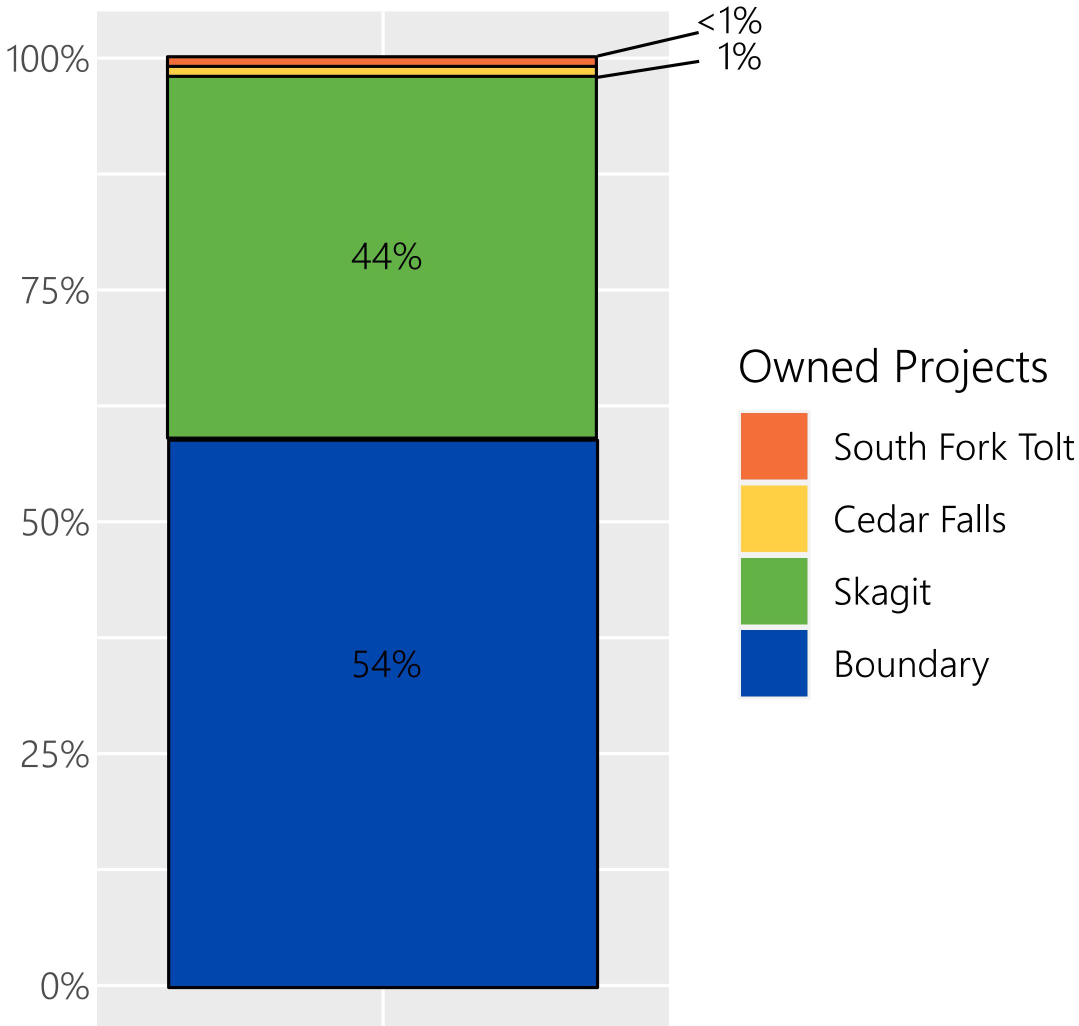


Table 1 City Light Owned Generation (aMW) 2002-2021

Year	Boundary	Ross	Diablo	Gorge	Cedar Falls	South Fork Tolt
2002	452	96	101	117	9	9
2003	408	83	84	106	7	6
2004	400	78	88	105	7	7
2005	395	64	74	89	4	5
2006	493	73	84	100	9	6
2007	415	98	94	123	8	6
2008	436	75	86	105	10	7
2009	410	71	78	96	9	6
2010	359	74	82	100	7	6
2011	514	99	105	125	13	6
2012	434	107	106	123	14	7
2013	396	83	94	109	9	6
2014	485	91	97	121	7	7
2015	396	78	88	109	5	6
2016	444	90	99	118	8	6
2017	437	85	79	114	10	6
2018	458	79	71	108	10	7
2019	378	60	69	95	5	3
2020	408	75	80	109	9	5
2021	367	94	96	113	10	6

City Light Power Purchase Contracts

City Light's largest power purchase contract is with BPA. The contract allows the utility to receive power from 31 hydroelectric projects, and several thermal and renewable projects in the Pacific Northwest. The energy is delivered over BPA's transmission grid. In December 2008, City Light signed a contract with BPA to continue City Light's access to the power resources that BPA markets through September 2028. Under the BPA contract, power is delivered in a block product in which power is delivered in monthly amounts shaped to City Light's annual net requirement, defined as the difference between City Light's projected annual load and the resources available to serve that load under critical water conditions.

The High Ross Agreement is an 80-year treaty with the Canadian Province of British Columbia; City Light abandoned plans to raise the height of Ross Dam in exchange for power purchases from British Columbia Hydro (acting through its subsidiary PowerEx). Power delivery and price are similar to the generation and costs City Light would have experienced had construction taken place. In 2021, the price of this energy is about a dollar per MWh because the cost portion, equivalent to debt service that would have been issued to build the High Ross Dam, will terminate. PowerEx delivers the power to City Light over its and BPA-owned transmission lines. This agreement is currently being amended to include needed clarifications, brought on by CETA legislation, on the greenhouse gas emissions of this energy resource.

The Seven Mile Encroachment contract associated with the High Ross Treaty allowed BC Hydro to raise the Seven Mile Reservoir, which reduced the output at Boundary Dam due to encroachment on the tailrace. Therefore, BC Hydro returns or pays for the energy that would otherwise have been generated at Boundary Dam if Seven Mile Reservoir had not been raised.

The Lucky Peak Contract is a hydro project located near Boise, Idaho, that has contracted with City Light for over 30 years. Because of its location near Boise, Lucky Peak can sell power to all major western trading hubs (Mid-Columbia, California Oregon Border, Palo Verde, Mead, and Four Corners) without encountering normal transmission constraints, meaning City Light has the option to sell to the highest price market. City Light has power purchase contract rights to Lucky Peak output (approximately 34 aMW annually) until 2038.

For several years, City Light has entered into a succession of 2-year Lucky Peak energy exchange contracts. In these exchange contracts, City Light receives firm energy closer to its balancing area in exchange for weather-dependent hydro energy produced at Lucky Peak. Through these contracts, City Light eschews the risk associated with this variable energy resource and risk from energy market dependence, as well as avoids securing relatively long-distance transmission to bring Lucky Peak energy to load. The exchange also allows City Light to choose the months in which the firm energy is received, helping to secure firm support in lean months. For example, Lucky Peak exchange energy is especially valuable to City Light in August, when hydro resources are very low and power prices tend to be high. Lucky Peak exchange energy is considered unspecified power, and hence has greenhouse gas emissions associated with it.

The Priest Rapids Project consists of two dams: the Priest Rapids Dam and the Wanapum Dam. City Light purchases power from this project under two agreements with Grant PUD, which owns and operates the project. The term of the agreements extends to the end of the current federal license for the project, April 2052. Seventy percent of Priest Rapids Project's output has been allocated to Grant PUD. Under one agreement, City Light purchases about two to three average megawatts of output at the production cost of the facility. Under the second agreement, City Light has the option to receive a share of proceeds, if any, from an auction of 30 percent of the output, or to purchase the share of the output at the price set in the auction. City Light uses BPA transmission to deliver the power it receives from this project to its customers.

The Columbia Basin Hydro contracts comprise power from five Columbia River Basin hydroelectric projects. The projects are part of three irrigation districts, so electric generation is mainly in the summer months. City Light has contracts to buy half of the output, or about 27 aMW, from all five Columbia River Basin hydroelectric projects. City Light's contracts expire at different times between 2022-2027.

The Columbia Ridge Landfill Gas Project is a 20-year power purchase agreement with Waste Management Renewable Energy, LLC to purchase approximately 12 aMW each year from its landfill. As organic materials decay in a landfill they release methane, which can be collected and burned to produce electricity. The plant began commercial operations in January 2010. The Columbia Basin Co-Op and BPA provide transmission. This project qualifies under the Energy Independence Act (or I-937) as renewable energy.

The King County West Point Treatment Plan Project is a 20-year power purchase agreement that began in February 2010 with King County to purchase the output from a methane gas producing digestor at the wastewater treatment plant in Discovery Park. The expected output is 2.5 aMW each year. Methane is a by-product of the treatment process, which is collected and burned to produce electricity. The plant is inside City Light's service area, so no third-party transmission is required. This project also qualifies under the Energy Independence Act (or I-937) as renewable energy.

Table 2 City Light's 2021 Energy Resources

Resources	2021 Energy Produced (MWh)	% of Grand Total	Year FERC License Expires	Year Contract Expires
Owned Generation				
Boundary	3,211,443	28.1%	2055	
Gorge	988,738	8.7%	2025	
Diablo	847,067	7.4%	2025	
Ross	823,907	7.2%	2025	
Cedar Falls	83,424	0.7%		
South Fork Tolt	54,658	0.5%		
Total Owned	6,009,237	52.6%		
Contracts				
BPA Block	4,119,204	36.1%		2028
Priest Rapids	23,601	0.2%	2052	2052
Columbia Basin Hydro	265,850	2.3%	2030-2032	2022-2027
High Ross	315,101	2.8%		2066
Seven Mile	10,533	0.1%		2066
Lucky Peak	221,981	1.9%	2035	2038
Columbia Ridge	92,937	0.8%		2028/2033
King County WW	10,909	0.1%		2033
Stateline Wind	360,191	3.2%		2022
Total Contracts	5,409,774	47.4%		
Grand Total	11,415,322	100.0%		

City Light Energy Efficiency

Energy efficiency programs encourage customers to use power more efficiently and allow the utility to defer the acquisition of expensive new resources, including those that negatively affect the environment. Energy efficiency is low cost and has low environmental impacts, including no greenhouse gas emissions. It also is a local resource and can be strategically deployed within City Light’s service territory. Integral to developing the IRP, energy efficiency programs will help City Light maintain its status as a greenhouse gas neutral utility, support the City’s environmental and climate change policy goals, and meet the requirements of I-937.

Energy efficiency programs are designed for all customer classes and address specific energy end-uses such as lighting, water heaters, laundry appliances, HVAC, motors, and manufacturing equipment. These programs provide energy efficiency information and financial incentives that encourage customers to, for example, insulate their homes, install energy efficient appliances, or install efficient lighting in commercial and industrial establishments.

City Light Energy Conservation Programs

In 2021, City Light's energy conservation programs accounted for approximately 91,271 MWhs. In City Light's 2022 Conservation Potential Assessment (CPA), future energy conservation targets will be over seventy percent commercial sector, with the remaining thirty percent split between residential and industrial sectors.

City Light's 2022 CPA has outlined achievable economic potential, by sector, in Table 3.

Table 3 2022 CPA Achievable Economic Potential (aMW)

Sector	2-Year (2022-2023)	4-Year (2022-2025)	10-Year (2022-2031)	20-Year (2022-2041)
Residential	2.90	5.22	11.16	17.91
Commercial	13.85	25.98	57.08	77.48
Industrial	1.99	4.03	8.65	10.44
Total	**18.74**	**35.23**	**76.89**	**105.83**

City Light Power Market Resources

City Light sells and purchases power in the wholesale market to supplement its owned generation and contracted resources. Market participation is particularly important to City Light because 90 percent of City Light's current resource portfolio is hydroelectric, which is highly variable as it is dependent on water availability and operating restrictions. Water conditions vary by season and year. Under average conditions, City Light has surplus energy throughout most of the year that can be sold in the electric market to offset costs. When there is not enough hydropower to meet demand, which is typically from mid-July to mid-September, City Light makes market purchases to compensate for the deficit.

City Light joined the Energy Imbalance Market (EIM) in April of 2020. The EIM manages real-time imbalances on the grid economically, reliably, and automatically. Deviations in supply and demand occur in every hour resulting in a mismatch, or imbalance, between available electricity versus what is needed by consumers. Balancing Authorities (BAs) have traditionally tried to manage these imbalances by relying on manual dispatches and extra power reserves. An EIM solves these imbalances in real-time with more precision through an automated 5-minute energy dispatch service. EIM's automation and economic dispatch lower costs for participants and become even more valuable as additional renewable resources connect to the grid.

The EIM, managed provided by the California Independent System Operator (CAISO), allows other BAs to leverage the benefits of real-time balancing while also maintaining all their existing authority. BAs remain responsible for procurement or self-provision of reserves and other ancillary services. The EIM does not change City Light's responsibilities for resource adequacy, reserves, or other BA reliability-based functions as required by the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC). EIM does, however, change how participating BAs deal with imbalances in real time. All BAs start the hour with matched generation and forecasted load. Imbalances occur within the hour because load and generation typically vary slightly from what is forecasted. Resources within the EIM area can voluntarily provide bids to dispatch their facilities to manage these imbalances. The EIM will automatically look across the expanded EIM region and dispatch the most economical bids available to meet these imbalances. The real-time optimization determines the least cost mix of resources and dispatches them to resolve these imbalances. The optimization also manages congestion on the transmission system by respecting transmission limits.

Table 4 shows 2020 and 2021 specified sales for Ross and Boundary dams. Specified sales include bilateral and EIM sales.

Table 4 City Light Specified Sales (MWh)

	Boundary		Ross	Annual Totals
	Bilateral	EIM	EIM	
2020	794,746	41,304	10,400	846,450
2021	351,077	197,136	42,333	590,546
Average	572,912	119,220	26,367	718,498

When City Light sells energy from a specific resource, it is unable to claim that portion of energy in its own portfolio. Since these specified sales are typically sourced from City Light's owned hydro resources, it reduces the overall claims of that given resource. Selling specified energy from renewable or non-emitting sources will impact the overall proportion of those types of resources considered to be serving City Light's retail load.

City Light Participation in Regional Planning

Independent system operators (ISOs) and Regional Transmission Operators (RTOs) were formed across North America during the late 1990's and 2000's as regulatory bodies to achieve several electricity industry objectives, including electricity market fairness, efficiency, and reliability. However, to date, an ISO/RTO has not been established in the West, with the exception of the CAISO covering most of California. Some reliability and market fairness and efficiency policies for the West have come from FERC, WECC, and other regional entities such as the Western Power Pool (WPP), formerly known as the Northwest Power Pool (NWPP). The NWPP has coordinated other regional reliability programs, including a Reserve Sharing Program, Pacific Northwest Coordination Agreement, and Western Frequency Response Sharing Group. In recent years, the impending retirement of greenhouse gas-emitting energy generation resources, electrification efforts, and clean energy legislation and policies requiring increased integration of intermittent renewable resources have led to increasing concerns over system reliability.

City Light has been working with the WPP and regional stakeholders since 2019 to design and implement the Western Resource Adequacy Program (WRAP). The program aims to enhance and increase electricity reliability for entities across the pacific northwest and the desert southwest. The program is still under development and as of summer 2022, the program will consist of three phases:

- The non-binding phase in the years 2023-2024,
- The optional binding phase in the years 2025-2027,
- The required binding phase in the years 2028 and beyond.

In the binding phase, program design centers on a regional reliability requirement designed to ensure that any participating load serving entity (LSE) will be able to purchase available energy from other participating LSEs, needed to serve load in the event of extreme system demand. Based on self-reported generation capability from participating LSEs, the program operator will model regional requirements to maintain a 0.1 Loss of Load Expectation (LOLE; for definition and discussion of LOLE, please see the Resource Adequacy appendix) reliability standard across the program footprint.

The program is capacity-based for all thermal and other dispatchable generation resources, but generation capability will be based on historical energy generation for intermittent renewables like wind, solar, and run-of-river hydro, and for energy-constrained resources like storage hydro. The total regional capacity needed to meet that requirement will be allocated equitably to program participants based on amount of load served, via an assigned planning reserve margin (PRM), which will be updated prior to the start of each season. Once the program moves into its binding phase, scheduled to start in January 2023, participating LSEs will be required to demonstrate sufficient capacity to meet their assigned PRM seven months in advance of the next summer or winter season. City Light will be integrating assigned PRM into any capacity-based modeling and planning to ensure compliance and benefit eligibility as a participant in the WRAP.

APPENDIX 2: LOAD FORECAST AND REGULATORY IMPACT ON RESOURCE NEEDS

Load Forecast

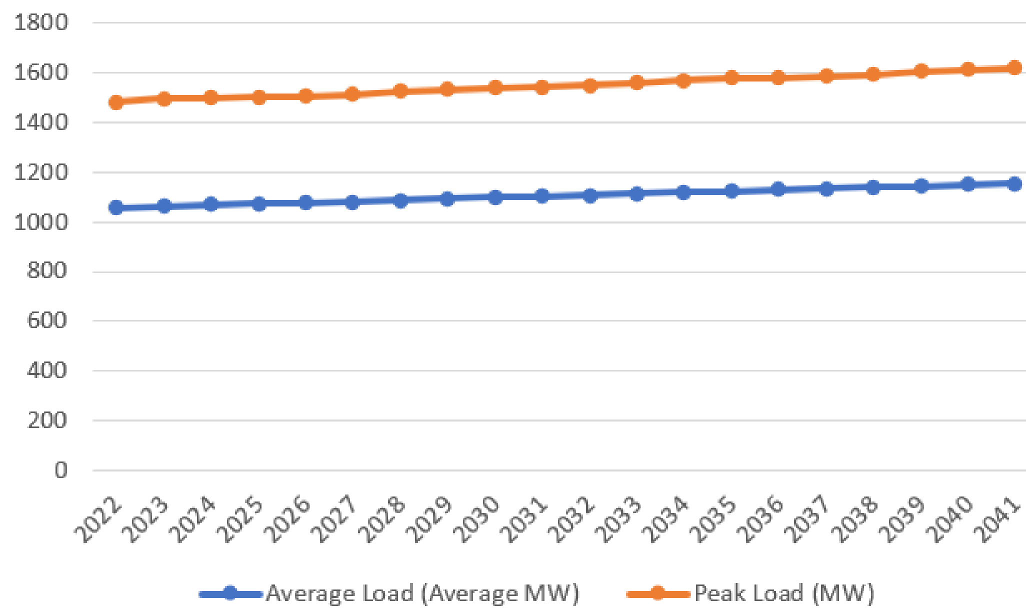
One of the most critical steps in future power planning is the determination of future power supply needs. For the purpose of the IRP, this involves an assessment of how much total energy City Light customers are expected to consume over a period of time (load), what is the maximum amount they are expected to consume instantaneously (peak demand), and how rapidly they are expected to change their instantaneous needs (flexibility or ramp).

The first step in assessing the need for additional resources is forecasting City Light's future electricity demand and establishing a target for the desired level of resource adequacy. The IRP long-range forecast calls for continued load growth trends in electricity demand for the service area. This growth is primarily driven by projected economic and population growth for the region. Relative to previous IRPs, load growth is forecasted to grow at a slower pace, due in part to changing regulations, building codes, and customer behaviors. This is similar to regional and national trends.

The 2022 IRP will be centered around City Light's 2020 system load forecast and will be referred to as the 2022 IRP Baseline load forecast. The 2022 IRP will also feature load forecasts from an Electrification Rapid Market Advancement (RMA) scenario, as well as climate change scenarios.

It should be noted that the IRP treats energy efficiency as a supply resource and evaluates energy efficiency in the same way as it evaluates other supply resources. As such, the graph below in Figure 1 shows the 2022 IRP Baseline load forecast with historic energy efficiency, but without the impacts of new energy efficiency.

Figure 1 2022 IRP Baseline peak and average energy load forecast (before new energy efficiency)



As part of the IRP process, City Light identifies future supply needs for the next 20 years based on the ability of existing supply to meet future forecasted demand, regulatory requirements, and uncertainty in supply and demand. To help identify these needs City Light performs a resource adequacy assessment and forecasts how much eligible renewable generation will be needed to comply with regulations. The Resource Adequacy appendix goes into much more detail about this assessment.

Regulatory Requirements

City Light will soon be required to comply with several regulations, both new and existing, aimed at addressing the greenhouse gas (GHG) emissions associated with the energy we generate, transact, and deliver. Some of these policies include, but are not limited to:

- Washington's Energy Independence Act (existing since 2006)
- Washington's Clean Energy Transformation Act (relatively new to Washington)
- Washington's Climate Commitment Act (new to Washington)
- California's Global Warming Solutions Act (existing in California but new to City Light)
- Washington's Clean Fuel Standard (new to Washington)

The goals and requirements of these regional policies will help City Light, as well as other utilities, accelerate the momentum necessary to reduce state and regional energy sector emissions. In addition to reducing emissions, a number of these regulations seek to ensure these energy transitions are done in an equitable manner by putting environmental justice and equity at the center of these climate policies.

Though much of City Light's portfolio is already served by renewable and non-emitting resources from within the region, City Light must continue to squeeze out the remaining portion of fossil fuels in its portfolio to comply with and meet the objectives of these new requirements. Reducing the emissions associated with the energy sector will require a broad portfolio of solutions. Leveraging these solutions will require additional research and testing to ensure they are integrated safely and cost-effectively. These actions must be taken to meet compliance obligations and customers' energy needs.

Washington's Climate Commitment Act and Clean Fuel Standard, which were passed in 2021 and 2022 respectively, will not be featured in the 2022 IRP due to ongoing rulemaking at the time of this writing and analysis. It is expected that City Light's 2024 IRP Progress Report will feature one or both policies in some form. California's Global Warming Solutions Act became applicable to City Light when it joined the Energy Imbalance Market in 2020. This policy also does not yet have any defined impacts assumed in the 2022 IRP.

In the next two regulatory sub-sections for I-937 and the Clean Energy Transformation Act (CETA), the planning status of these legislative requirements will be shown with the current City Light portfolio of resources, which includes the 2022 Conservation Potential Assessment energy efficiency program savings. The status of these regulatory requirements will be shown with the expected 2022 IRP Baseline load and the Electrification RMA load scenarios.

I-937 Renewable Portfolio Standard

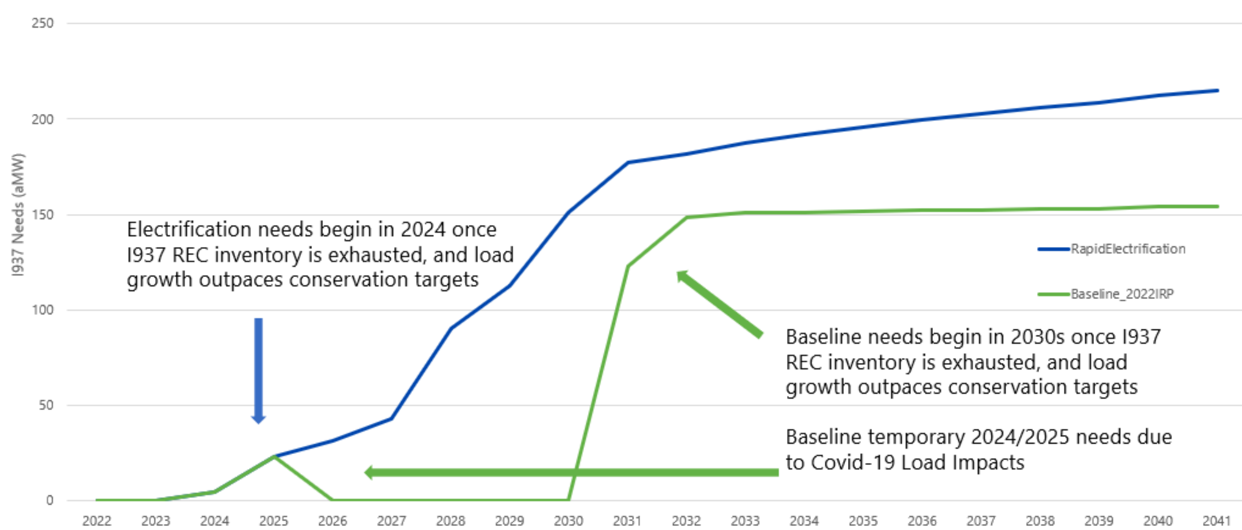
The Washington state Energy Independence Act, also known as I-937, requires electric utilities serving at least 25,000 retail customers to use renewable energy and energy conservation. I-937 annual compliance can be met in three ways:

- If a utility has "load growth," each utility shall use eligible renewable resources and/or renewable energy credits (RECs) to meet 15% of its delivered customer retail load.
- If a utility has "no load growth," each utility shall use eligible renewable resources and/or RECs to meet 1% of its retail revenue requirement.

- If a utility spends at least 4% of its retail revenue requirement on the incremental cost of renewable energy and/or RECs.

To comply with I-937 requirements, City Light has been using the "no load growth" compliance option since 2019. If City Light has increasing load over four consecutive years, it must meet 15% of sales with eligible resources, RECs, or a combination. Load increased in 2021 compared to 2020, and if load growth continues, City Light will need to take additional actions to ensure compliance with I-937 as early as 2024, as shown in Figure 2. With new wind and solar additions potentially starting in 2026, as well as the RECs already committed, City Light is well positioned for meeting I-937 requirements for renewable energy well into the future. After 2030, if City Light has a greenhouse gas free energy portfolio for four years in a row for Clean Energy Transformation Act (CETA) compliance, then City Light does not have to take any additional actions for I-937.

Figure 2 I-937 Needs



Clean Energy Transformation Act (CETA)

With an existing energy portfolio typically more than 90% renewable or non-emitting, City Light is well-positioned for meeting the following near term CETA milestones:

- Utilities must remove coal-fired generation from Washington's allocation of electricity by 2026.
- Washington retail sales must be greenhouse gas neutral, with at least 80% renewable or non-emitting by 2030.
- Washington retail sales must be 100% renewable or non-emitting by 2045.

The Clean Energy Implementation Plan (CEIP) was the first planning document submitted to the Washington Department of Commerce under CETA and was submitted January 1st, 2022. As part of the CEIP compliance, City Light established its annual hydro median condition as the culmination of individual monthly medians of City Light's historical monthly hydro generation from the 1999 to 2020 time period. This median hydro data is used in the CEIP and the Clean Energy Action Plan, both of which are a part of CETA planning policy.

Another aspect of CETA compliance is to consider the Social Cost of Greenhouse Gas (SCGHG[1][2]) when developing integrated resource plans and clean energy action plans. In the 2022 IRP, City Light's Seattle Area Resource Additions Advisor (SARAA) capacity expansion model decides if, on a monthly basis, it is more cost effective to fulfill energy shortfalls with new renewable energy project(s) or to purchase electricity from the market that is assumed to be unspecified and therefore have a SCGHG penalty added to the cost of the electricity. Once a portfolio of resources is created using the SARAA model, the SCGHG adder is one of the cost components of a portfolio's total cost. In the 2022 IRP, there are three ways of incurring a SCGHG cost penalty associated with a portfolio's unspecified energy:

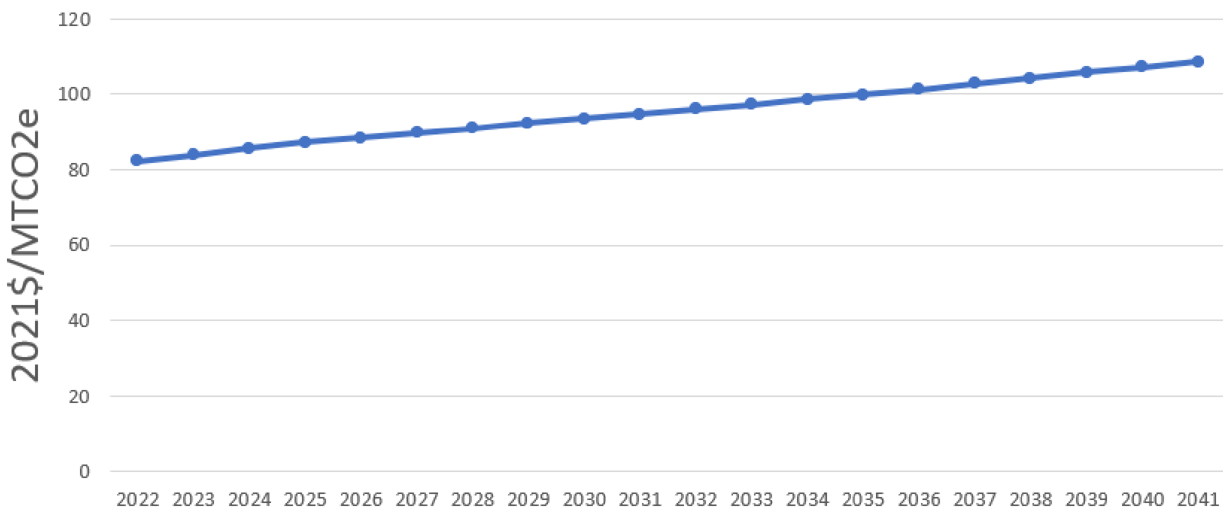
1. a small percentage of unspecified power in the BPA block contract,
2. City Light long-term contracts (*e.g.*, High Ross contract, Lucky Peak exchange),
3. City Light spot market purchases from unspecified generating sources

Any SCGHG cost calculations assume the CETA assigned emissions rate of 0.437 metric tons of carbon dioxide equivalent (CO2e) per MWh of unspecified energy and the SCGHG in 2021 dollars per metric ton of CO2e. The assumed SCGHG, prescribed by the Washington Department of Commerce, in 2021 dollars per metric ton of CO2e is shown in Figure 3.

[1] https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act/social-cost-carbon

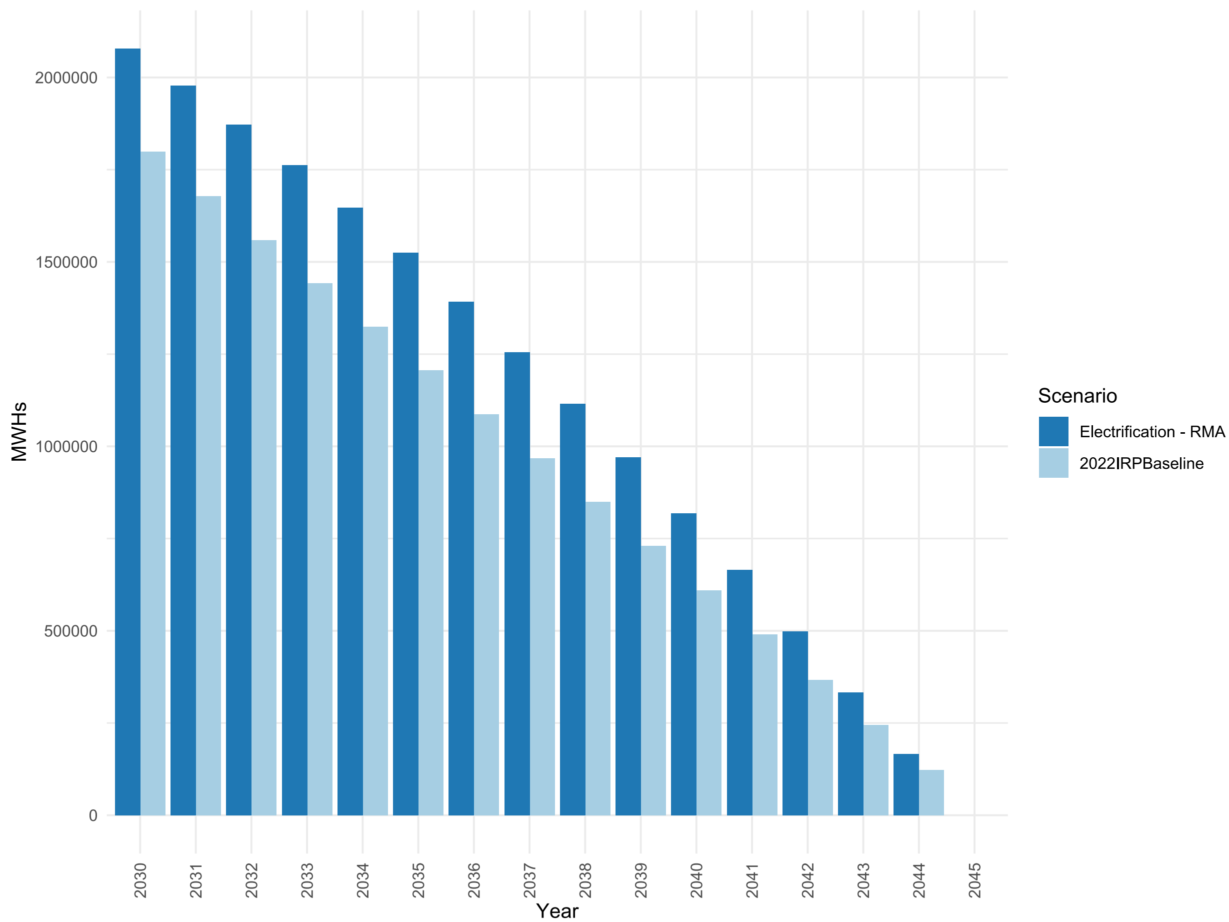
[2] revised code of Washington related to IRPs that governs SCGHG methodology is 3a under 19.280.030

Figure 3 2022 IRP Assumed Social Cost of Greenhouse Gas (2022-2041)



Another important aspect of CETA compliance that can be found in the 2022 IRP is related to the 2030 CETA milestone that utilities' retail sales need to be greenhouse gas neutral with at least 80% being greenhouse gas free. This milestone is also modeled in City Light's capacity expansion SARAA model. The model must choose a mix of resources that is 80% greenhouse gas free by 2030. For example, Figure 4 details that, under median hydro conditions, only a certain number of MWhs of unspecified power are allowed each year starting in 2030. This allowance linearly decreases until 2045, when CETA requirements disallow unspecified power given its inherent GHG content. The allowance is one of several model constraints that dictate a portfolio's mix of resources. The allowances in Figure 4 were calculated for the 2022 IRP Baseline load forecast scenario as well as the Electrification RMA scenario.

Figure 4 CETA Unspecified Power Allowance Trajectory Based on Load (2030-2045)



Another aspect of CETA compliance is comparing the allowed amount of unspecified power from Figure 4 with the expected amount of unspecified power under different load forecast scenarios. Per CETA, from 2030 to the end of 2044, up to 20% of a utility's compliance obligation can be in the form of alternative compliance. In other words, from 2030 to the end of 2044, at least 80% of retail load must be supplied with electricity that is greenhouse gas free, with up to 20% being available for emitting electricity sources as long as those emissions are offset. For example, Table 5 shows that in the year 2030 the 2022 IRP Baseline scenario, per CETA, would allow approximately 1.8 million MWhs of emitting energy to be in City Light's portfolio but requiring offsets. However, City Light should expect only about 152,000 MWhs of unspecified power (~82,000 MWhs from market purchases and ~70,000 MWhs from BPA block contract) *if* no new non-emitting resources are added to its portfolio (see Appendix 5: Create Top Portfolio for quantity and timing of planned new non-emitting resources). This means that City Light is well positioned to meet the CETA 2030 milestone.

Table 5 2022 IRP Baseline CETA Emitting Allowance Trajectory Compared to City Light's Portfolio

Year	2022 IRP Baseline CETA Allowable Emitting Resources Trajectory (MWhs)	2022 IRP Baseline Expected Unspecified Emissions (MWhs)
2030	1,799,509	152,000
2040	1,829,932	89,000*

*Assumes BPA block contract 100% clean by 2040, so expected emissions from market purchases only

Table 6 Electrification RMA CETA Emitting Allowance Trajectory Compared to City Light's Portfolio

Year	Electrification RMA CETA Allowable Emitting Resources Trajectory (MWhs)	Electrification RMA Expected Unspecified Emissions (MWhs)
2030	2,078,019	216,000
2040	2,456,742	1,207,000*

*Assumes BPA block contract 100% clean by 2040, so expected emissions from market purchases only

There is a lot of uncertainty with the pace of electrification and its impact on demand for electricity, as well as its impact on compliance with Washington state energy policies. Under the 2022 IRP Baseline scenario, City Light is well-positioned to comply with I-937 as there are only some short-term REC needs for the years 2024 and 2025, with no further needs until the 2030s. For CETA compliance under the 2022 IRP Baseline scenario, City Light is well-positioned as the portfolio is already approximately 90% greenhouse gas free on a net-monthly basis. Under the Electrification RMA scenario, City Light would have REC needs as early as in 2026 for I-937 and significant alternative compliance needs in 2030 for CETA. The Electrification RMA scenario has a faster load growth pace than is currently expected, and it is used to stress test City Light's baseline resource and policy needs.

APPENDIX 3: RESOURCE OPTIONS

As part of the 2022 IRP, both supply side and demand side resources are considered to meet City Light's portfolio requirements over the 20-year IRP time horizon: 2022 through 2041. For supply side resources, a mix of solar, batteries, and wind resources are considered. For demand side resources, energy efficiency, demand response, and customer solar programs are considered.

Supply Side Resources

Utility scale solar resources in eastern Washington and southeast Oregon are considered for the 2022 IRP. To calculate the Electric Load Carrying Capability (ELCC) of potential new resources to be included in City Light's portfolio model, as well as anticipated energy delivered to its service territory, estimated generation patterns of these new resources were prepared. The National Renewable Energy Laboratory (NREL) System Advisor Model (SAM) tool is used to estimate electricity generation of solar projects in the above-mentioned locations. The SAM software uses weather files gathered from the National Solar Radiation Database (NSRDB), which is a serially complete collection of hourly and half-hourly values of meteorological data and the three most common measurements of solar radiation: global horizontal, direct normal and diffuse horizontal irradiance. SAM uses this meteorological data, in conjunction with solar panel specifications to predict generation patterns. The 2022 IRP framework methodology performs 22 SAM simulations of hourly generation patterns, each simulation using a different weather year from the available NSRDB set of 1998-2019. Commercial and local solar resources in Seattle use the same assumptions.

Utility scale wind resources in the Columbia River Gorge, Great Falls, Montana, and offshore of NW Oregon coast are also considered as supply side resources. The weather data for these locations was taken from the NREL Wind Toolkit and taken at the 100-meter height for the land-based turbines, 80-meter for the offshore turbines. The 2022 IRP framework uses eight SAM simulations of hourly generation patterns, each simulation using a different weather year from the available NREL Wind Toolkit set of 2007-2014.

For the 2022 IRP, it is assumed that Montana wind and offshore wind would not be viable due to the necessary transmission to bring the energy to Seattle being unavailable until 2032. Also, offshore wind is also not technologically feasible until 2032. Table 1 and Figure 1 detail the simulated capacity factors of the various wind and solar resource options for the 2022 IRP.

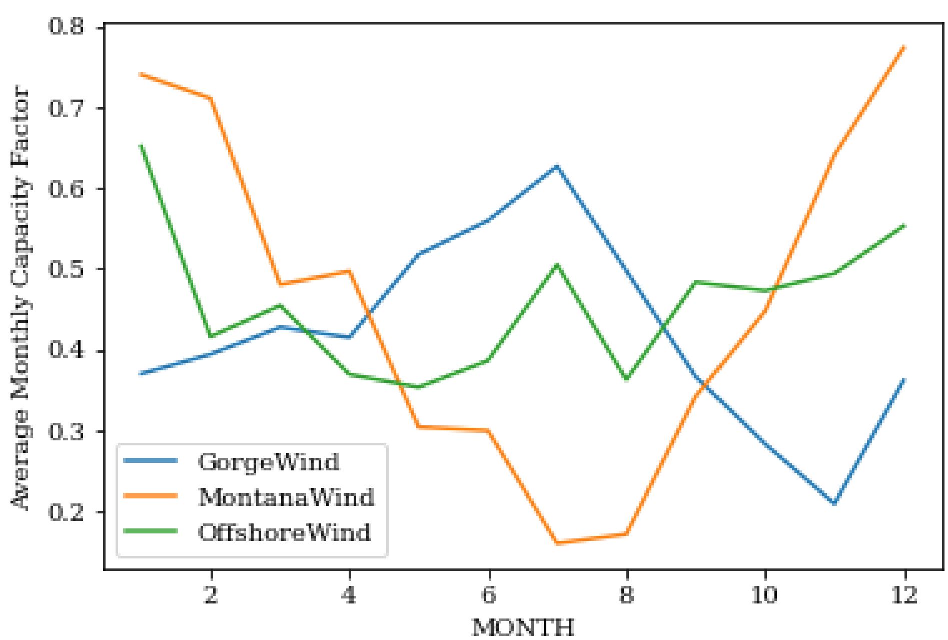
Table 1 Wind and Solar Capacity Factors by Location, All Simulated Years

Resource	Capacity Factor (%)
E WA Solar	25-28%
SE OR Solar	26-30%
Columbia River Gorge Wind	40-44%
Montana Wind	44-49%
Offshore Wind	40-50%
SE OR Solar + Battery	29-33%
Seattle Solar	13-16%

The supply side solar and wind resources range in capacity factor between 25-30% and 40-50% respectively. Batteries paired with solar increased the capacity factor to above 30% and demand side Seattle solar ranges between 13-16%.

As part of the 2022 IRP process, the Electrification RMA scenario showed some significant energy needs in the winter. From the resource options used in this IRP, the wind resources are the ones that have a higher contribution in the winter. The characteristics of these wind resources are explored further in this appendix.

Figure 1 Monthly Wind Capacity Factors of Median Production Year



Each wind resource has a distinctly different distribution of what months produce more energy. Gorge wind does best in the summer, Montana wind in the winter, and offshore wind has a much more consistent output throughout the year. The top three expected production months for Gorge wind are May, June, and July; for Montana wind, they are January, February, and December; and for offshore wind, they are January, July, and December. Table 2 contains several summary statistics of the wind hourly shapes.

Table 2 Wind Capacity Factor Distributions of Median Production Year

Statistic	Gorge Wind	Montana Wind	Offshore Wind
mean	0.420	0.462	0.459
q25	0.050	0.040	0.090
median	0.299	0.347	0.363
q75	0.837	0.984	0.938
std	0.386	0.415	0.388
skew	0.398	0.221	0.291
kurtosis	-1.455	-1.680	-1.521

The statistics in Table 2 further describe the distribution of the capacity factors for each wind resource. A higher mean, q25, median, and q75 are better than lower. For example, Gorge wind performs the worst in these three statistics, implying that it has the least desirable capacity factor overall. Offshore wind has the highest capacity factors for q25 and median, and has middling standard deviation, skew, and kurtosis. This means that while offshore wind may not have the highest maximum capacity factor, it does tend to do better on the low end and is again more consistent overall. Montana wind has the highest mean and q75, but also the lowest q25 and highest standard deviation. This data, along with the data in Table 3, suggests that Montana Wind can be highly variable.

Table 3 Additional Wind Resource Statistics for Median Production Year

	Hours of Zero Energy Production in Year	Significant Hour to Hour Production Changes
Gorge Wind	1322	19
Montana Wind	1561	54
Offshore Wind	1295	6

The first column in Table 3 counts the number of hours over the course of the year with a capacity factor equal to zero, meaning no energy is produced. In the first column, offshore wind is the best with just under 1,300 hours of zero production; Montana wind is the worst with over 1,500 hours without generating energy. The final column counts how many times the capacity factor jumps by more than 0.9 from one hour to the next. The best is offshore wind with only 6 hours, and the worst is Montana wind with over 50 large hourly jumps in capacity factor. While procuring any wind resource would help City Light's portfolio's length and position, it may also be challenging to manage generation uncertainty. For example, City Light's participation in the Energy Imbalance Market (EIM), could create uncertainties related to reserves requirements. This is because City Light is forced to hold Northwest Power Pool (NWPP) reserves at a number based on 3% of generation total and 3% of hourly load.

Effective Load Carrying Capability (ELCCs) of Supply Side Resource Choices

As part of the evaluation of resource choices the effective contributions of wind and solar generating resources on City Light's portfolio not only depend on the weather at their location, but also on their ability to carry City Light's loads. This concept is known as a resource's Effective Load Carrying Capability (ELCC), and it details how well each type of resource contributes relative to a measure of the maximum amount of output the resource can produce. Calculations of ELCCs provide a way of understanding the flexibility value of a resource compared to City Light's existing portfolio of resources. For this 2022 IRP, the HYDRRA model (detailed in Appendix 8: Resource Adequacy), is used to estimate the ELCC contribution of all resource options per the 2022 IRP Baseline and Electrification RMA scenario loads following City Light's established resource adequacy metric.

Table 4 2022 IRP Baseline Supply Resources Electric Load Carrying Capability for December

Resource	December ELCCs			
	2026	2030	2035	2041
E WA Solar	0.155	0.153	0.159	0.147
SE OR Solar	0.134	0.111	0.155	0.096
Columbia River Gorge Wind	0.297	0.276	0.296	0.266
Montana Wind	0.725	0.687	0.706	0.650
Offshore Wind	0.581	0.543	0.545	0.517
SE OR Solar + Battery	0.193	0.158	0.197	0.153

Table 5 2022 IRP Baseline Supply Resources Electric Load Carrying Capability for August

Resource	August ELCCs 2026	2030	2035	2041
E WA Solar	0.318	0.365	0.381	0.418
SE OR Solar	0.366	0.410	0.440	0.407
Columbia River Gorge Wind	0.341	0.452	0.394	0.378
Montana Wind	0.092	0.102	0.124	0.190
Offshore Wind	0.460	0.445	0.458	0.437
SE OR Solar + Battery	0.461	0.476	0.485	0.487

Table 4 and Table 5 show the supply side resource options' ELCCs under the 2022 IRP Baseline load. The solar ELCC contributions in the winter are about half or less compared to the summer. For the winter the ELCCs over time are either flat or slightly declining, and for the summer the ELCCs are slightly increasing over time. For the wind ELCC contributions, depending on the projects there are major differences. Gorge wind's ELCC contributions in the summer are greater than the winter. For Montana wind the ELCC contributions in the winter are much greater compared to the summer. Offshore wind ELCC contributions are slightly greater in the winter compared to the summer.

Table 6 Electrification RMA Supply Resources Electric Load Carrying Capability for December

Resource	December Electrification ELCCs 2026	2030	2035	2041
E WA Solar	0.105	0.117	0.114	0.105
SE OR Solar	0.133	0.136	0.138	0.137
Columbia River Gorge Wind	0.280	0.298	0.343	0.310
Montana Wind	0.687	0.671	0.713	0.697
Offshore Wind	0.571	0.540	0.573	0.593
SE OR Solar + Battery	0.167	0.173	0.190	0.185

Table 7 Electrification RMA Supply Resources Electric Load Carrying Capability for August

Resource	August Electrification ELCCs			
	2026	2030	2035	2041
E WA Solar	0.370	0.367	0.466	0.469
SE OR Solar	0.405	0.415	0.488	0.487
Columbia River Gorge Wind	0.325	0.426	0.345	0.374
Montana Wind	0.177	0.090	0.143	0.153
Offshore Wind	0.388	0.313	0.481	0.474
SE OR Solar + Battery	0.453	0.512	0.518	0.521

Table 6 and Table 7 shows the supply side resource options' ELCCs under the Electrification RMA load. The solar ELCC contributions in the winter are about a third or less compared to the summer. For the winter the ELCCs over time are very flat, and for the summer the ELCCs are increasing over time. For the wind ELCC contributions, depending on the projects there are major differences. Gorge wind's ELCC contributions in the summer are greater than the winter. For Montana wind the ELCC contributions in the winter are much greater compared to the summer. Offshore wind ELCC contributions are slightly greater in the winter compared to the summer.

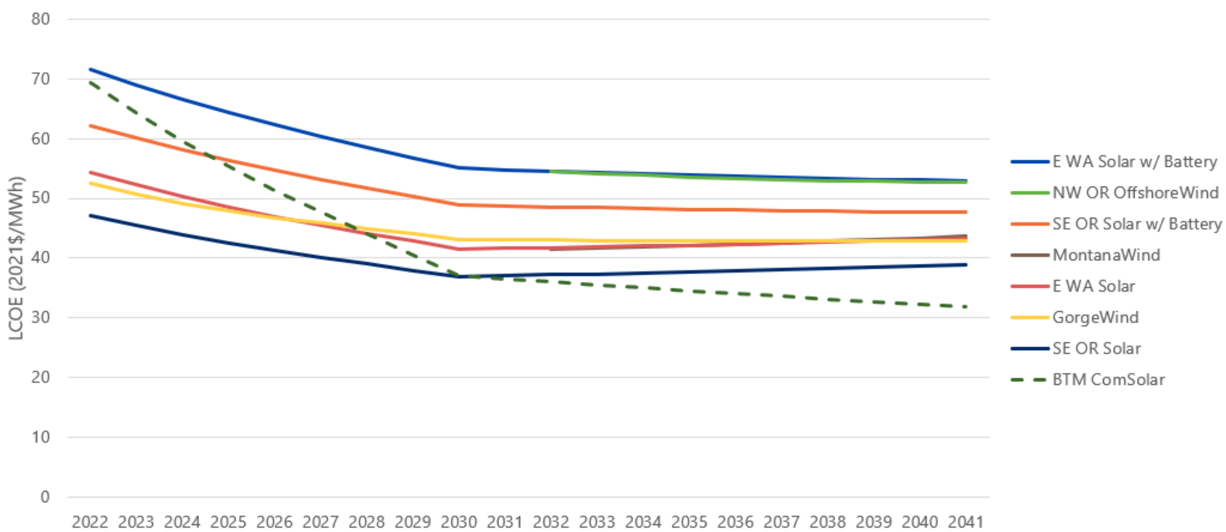
Overall, the ELCCs under the 2022 IRP Baseline load are greater than the ones under the Electrification RMA scenario load. The only exception are the solar resources which have higher ELCC contributions in the summer under the Electrification RMA load compared to the 2022 IRP Baseline load. The Electrification RMA scenario has a higher penetration of AC loads in the summer than the 2022 IRP Baseline, and it is likely that solar resources have a great impact on these loads due to its summer shape.

Supply Side Resource Options Costs

With the exception of Montana and offshore wind, the transmission costs all are assumed to be the BPA Long-Term Firm Point-to-Point rate of $20,567 estimated for 2022 (nominal $/MW – yr), escalating nominally 4% each year; a BPA Ancillary Services rate of nominal $2 per MWh estimated for 2022, escalating nominally 3% each year; and a BPA Scheduling, System Control & Dispatch rate of $3,944 estimated for 2022 (nominal $/MW – yr) in 2022, escalating nominally 4% each year. It is assumed Montana and offshore wind have approximately double the transmission costs. Transmission constraints are assumed to be no more than 250MW of capacity out of the Columbia River Gorge wind projects; no more than 100MW of capacity out of the SE OR solar projects; and no more than 350MW of capacity coming out of the E WA solar projects. It is assumed that Montana and offshore wind transmission is not available until 2032.

Wind, solar, and battery resource costs have been derived from several request for proposals City Light received from developers seeking Power Purchase Agreements (PPAs). All the resource costs are assumed to be in the form of a 30-year PPA contract in units of 2021 dollars per MWh. The delivered levelized cost of energy of the different resources shown in Figure 2 combines the hourly projected generation shape, PPA energy costs with the transmission, ancillary service, and system control costs.

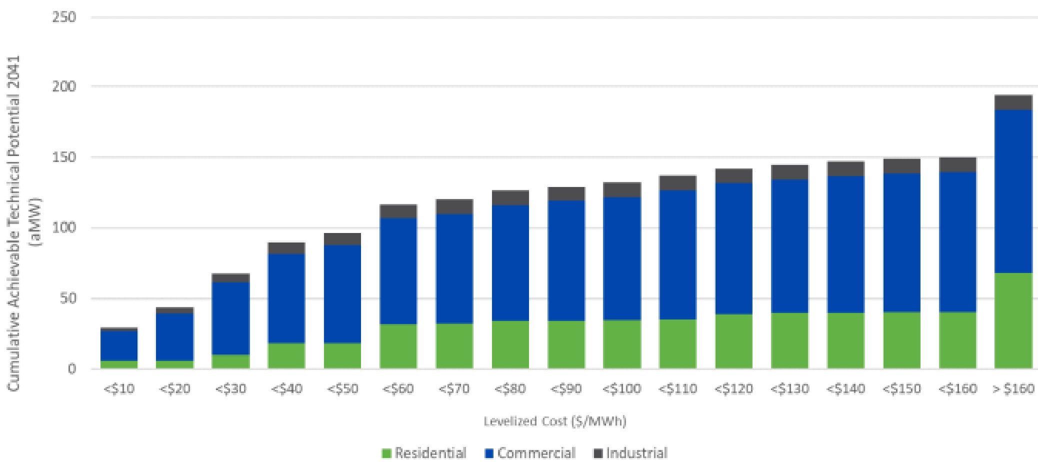
Figure 2 Delivered Levelized Cost of Energy



Demand Side Resources

Energy Efficiency (EE) has always been a part of City Light's IRP demand side resources. For the 2022 IRP, over 616 different energy efficiency programs have been considered. They consist of a combination of 8 different residential programs, 7 different industrial programs, and 11 different commercial programs. All these programs differ in both cost and energy, as well as the technologies deployed. Figure 3 shows the cumulative 20-year achievable technical potential supply curve used in the 2022 IRP.

Figure 3 Energy Efficiency 20-Year Technical Achievable Potential Supply Curve



Demand response options are new for the 2022 IRP. There are four options: a commercial/industrial curtailment program, a residential thermostat program, and two residential electric water heating programs. The commercial/industrial curtailment program can be called on up to five times per season and for four hours per call. For the 2022 IRP, it is assumed the summer season for the commercial/industrial curtailment program would be July and August; for the winter season it is assumed it would be November, December, January, and February; spring and fall would not feature any commercial/industrial curtailment calls. The residential thermostat demand response program is assumed to be able to be called up to five times each month, for three hours each call. The two residential electric water heating programs can be called up to two times per day, for six hours each call.

The four programs, their capacity growth over time, as well as annual cost over time are shown in Table 8 and Table 9.

Table 8 Demand Response Program Size Over Time

Program	Summer			Winter		
	2025	2030	2040	2025	2030	2040
Commercial/Industrial Curtail	2	11	11	2	8	9
Thermostat	1	7	12	3	36	51
Resistance Water Heating	6	40	65	7	43	70
Heat Pump Water Heating	0	2	3	1	5	7

Table 9 Demand Response Program Cost Over Time

Program	Summer			Winter		
	2025	2030	2040	2025	2030	2040
Industrial Curtail	$89,047	$444,026	$569,029	$68,771	$342,0998	$436,863
Thermostat	$25,760	$163,743	$348,878	$99,811	$965,311	$1,708,351
Resistance Water Heating	$727,960	$1,455,580	$2,440,360	$727,960	$1,455,580	$2,440,360
Heat Pump Water Heating	$129,768	$259,021	$433,563	$129,768	$259,021	$433,563

Effective Load Carrying Capability (ELCCs) of Demand Side Resource Choices

Table 10 2022 IRP Baseline Demand Resources Electric Load Carrying Capability for December

Resource	December ELCCs			
	2026	2030	2035	2041
Commercial EE	-0.429	-0.498	0.374	0.954
Industrial EE	1.001	0.985	1.064	0.981
Residential EE	-0.202	-0.295	1.082	1.054
Industrial Curtail DR	0.08	0.106	0.086	0.073
Thermostat DR	0.164	0.162	0.16	0.117
Resistance Water Heating DR	0.297	0.267	0.241	0.229
Heat Pump Water Heating DR	0.303	0.379	0.317	0.223
Seattle Solar	-0.287	-0.048	0.146	0.103

Table 11 2022 IRP Baseline Demand Resources Electric Load Carrying Capability for August

Resource	August ELCCs			
	2026	2030	2035	2041
Commercial EE	0.353	0.456	0.651	1.040
Industrial EE	1.775	0.655	0.737	0.828
Residential EE	0.196	0.220	0.986	1.071
Industrial Curtail DR	0.020	0.022	0.029	0.063
Thermostat DR	0.118	0.127	0.154	0.290
Resistance Water Heating DR	0.254	0.266	0.287	0.295
Heat Pump Water Heating DR	0.228	0.252	0.294	0.519
Seattle Solar	0.22	0.036	0.104	0.031

Table 10 and Table 11 show the demand side resource options' ELCCs under the 2022 IRP Baseline load. The commercial and residential energy efficiency in both the winter and summer ELCCs are increasing over time. Note that for December, from the period of 2026 to 2030 the ELCCs for these two energy efficiency categories are negative, this is due to City Light's Bonneville Power Administration (BPA) Block Contract. This contract's energy allocation is set on a yearly basis; a reduction in load (which is what energy efficiency does), reduces the total allocation of this contract which negatively impacts the winter months in this period. Industrial energy efficiency ELCCs are flat, but the contribution is greater in the winter compared to the summer. The Demand Response ELCCs' contribution is relatively consistent between summer and winter periods; there is a shift in ELCCs in the late 2030s once the load growth of the 2022 IRP Baseline load outpaces energy efficiency's growth.

Table 12 Electrification RMA Demand Resources Electric Load Carrying Capability for December

Resource	December Electrification ELCCs			
	2026	2030	2035	2041
Commercial EE	0.832	1.082	1.132	1.152
Industrial EE	1.001	0.986	1.064	0.981
Residential EE	1.065	1.068	1.153	1.153
Industrial Curtail DR	0.00	0.00	0.00	0.071
Thermostat DR	0.182	0.155	0.153	0.147
Resistance Water Heating DR	0.105	0.166	0.138	0.124
Heat Pump Water Heating DR	0.192	0.231	0.174	0.148
Seattle Solar	0.048	0.039	0.030	0.076

Table 13 Electrification RMA Demand Resources Electric Load Carrying Capability for August

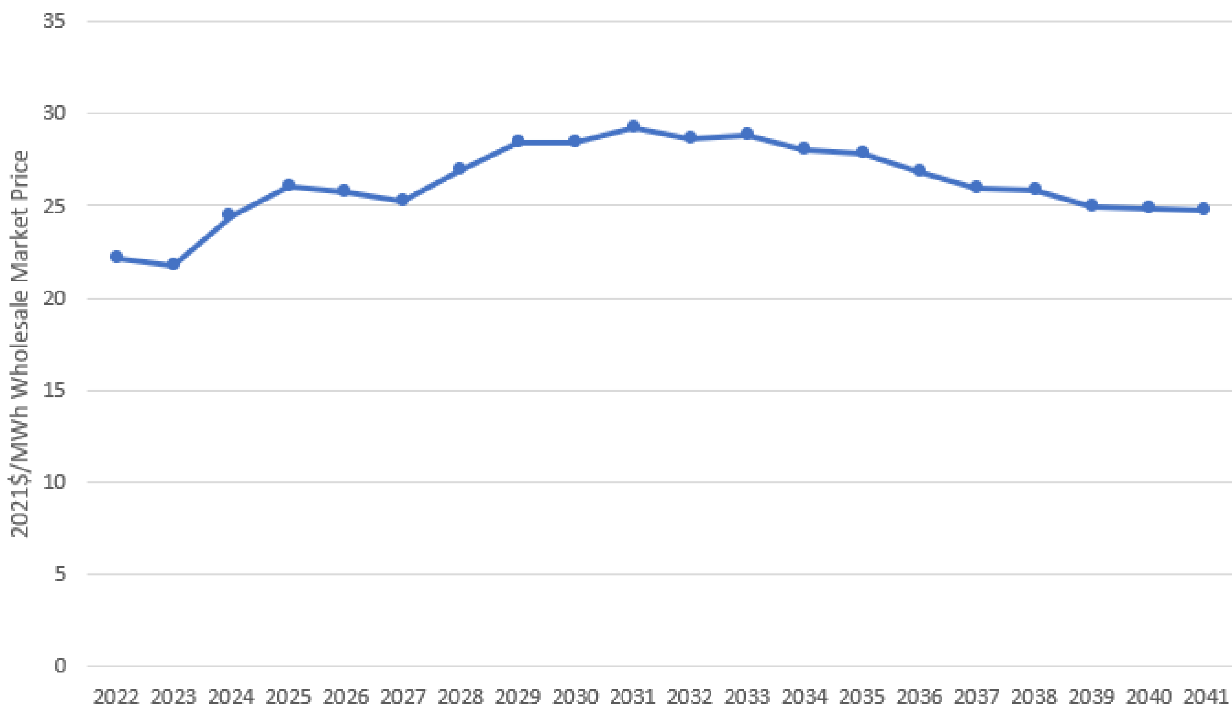
Resource	August Electrification ELCCs			
	2026	2030	2035	2041
Commercial EE	0.964	1.088	1.035	1.073
Industrial EE	1.775	0.655	0.739	0.828
Residential EE	1.427	0.772	1.066	1.054
Industrial Curtail DR	0.000	0.000	0.000	0.000
Thermostat DR	0.311	0.213	0.170	0.170
Resistance Water Heating DR	0.018	0.025	0.020	0.026
Heat Pump Water Heating DR	0.115	0.157	0.112	0.129
Seattle Solar	0.511	0.195	0.244	0.305

Table 12 and Table 13 show the demand side resource options' ELCCs under the Electrification RMA load. The energy efficiency programs show a lot of benefit in both the winter and the summer ELCCs apart from commercial EE in December 2026 and industrial EE from 2030 to 2041. The Seattle solar customer program shows more benefits compared to the 2022 IRP Baseline. The demand response ELCCs' contribution is much smaller compared to the 2022 IRP Baseline ELCCs apart from the thermostat DR for year 2026. For all EE, demand response, and Seattle customer solar programs, the potential under the Electrification RMA is likely understated as these programs were designed for the 2022 IRP Baseline load as part of the 2022 Conservation Potential Assessment. It is likely that the EE and DR potential designed with the Electrification RMA load would yield bigger benefits or potentials

Market Purchases

City Light also has the option to purchase energy from the market. Any market purchases will be according to the hourly wholesale market price forecast. The 2022 IRP Baseline wholesale market price forecast is shown in Figure 4.

Figure 4 2022 IRP Baseline Wholesale Market Price Forecast



Two alternative wholesale market price forecasts used in the 2022 IRP analysis are shown in Table 14, and are compared with the 2022 Baseline forecast.

Table 14 Alternative Price Forecasts

Additional Price Forecast	2025	2030	2035	2040
Alternative #1 – High	+9%	+13%	+14%	+27%
Alternative #2 – Low	-6%	-18%	-25%	-44%

A key feature of the 'High' alternative price forecast features a federal carbon policy starting in 2030. This case also offers a more modest renewable energy future in the region as compared to the 2022 IRP Baseline. This price forecast offers a reasonable 'Upper Bound' forecast when looking at average hourly prices and a regional buildout.

The 'Low' alternative price forecast seems to better consider regional clean energy policies, a faster transition to decarbonization, and hence has a more aggressive renewable energy build out than the 2022 IRP Baseline. This price forecast offers a reasonable 'Lower Bound' forecast and is used in the Electrification RMA scenario.

APPENDIX 4: PLANNING FOR 2022 IRP BASELINE & ELECTRIFICATION PORTFOLIO STRATEGIES

2022 IRP Baseline Scenario

As part of the 2022 IRP, the 2022 IRP Baseline is the main scenario, and it is the scenario in which resource plans will be based on. The components of this 2022 IRP Baseline include the following:

1) Current City Light resource portfolio
2) 2020 IRP Baseline load forecast
3) I-937 renewable portfolio standard requirements
4) CETA requirements
5) Resource adequacy requirements
6) Expected wholesale electricity price forecast
7) Resource options, prices, and estimated generation profiles
8) Resource options' effective load carrying capability
9) Transmission assumptions

Each of these components is created with the current expected conditions and is used to plan for the 2022 IRP. Each of these components is created for a new IRP and/or IRP cycle. Throughout this document, each of these will be briefly explained and explored.

For the first time not only is the 2022 IRP Baseline scenario created, but an electrification scenario is included as well. This electrification scenario's load forecast is drawn from the Electrification Assessment that City Light produced in partnership with EPRI that was released in early 2022. In the Electrification Assessment, the Rapid Market Advancement (RMA) electrification scenario, which is in alignment with Seattle's Climate Action Plan, is the middle of the three electrification scenarios in terms of electrification adoption rates. It is this Electrification RMA load forecast scenario that is used for the electrification scenario in the 2022 IRP. In the next section, the components of this Electrification RMA scenario will be identified.

Electrification Rapid Market Advancement (RMA) Scenario

The components of the Electrification RMA scenario that were updated or impacted by the load include the following:

1) Electrification RMA load forecast
2) I-937 renewable portfolio standard requirements

3) CETA requirements
4) Resource adequacy requirements
5) Expected wholesale electricity price forecast featuring more aggressive electrification and decarbonization
6) Resource options' effective load carrying capability
7) Transmission assumptions

The transmission constraints in the 2022 IRP Baseline scenario assumed no more than 250MW of capacity out of the Columbia River Gorge wind projects; no more than 100MW of capacity out of the SE OR solar projects; and no more than 350MW of capacity coming out of the E WA solar projects. It is assumed that Montana and offshore wind transmission is not available until 2032. However, in the Electrification RMA scenario, these transmission constraints had to be eliminated in order to develop the necessary wind and solar resources necessary to meet the higher electrification loads. The Electrification RMA scenario and associated load forecast is considered an aggressive electrification adoption rate, and so far it is not being considered for the default load forecast for City Light's main planning documents. The Electrification RMA scenario does however offer a reasonable 'book-end' of the possible implications of this more aggressive electrification adoption rate.

As shown per this breakdown, building this scenario was a significant effort to gain insights on the impacts of the city of Seattle's climate action plan which is to achieve zero net greenhouse gas emissions by 2050. One important shortcoming of this work is that the energy efficiency and demand response potentials are based on the 2022 IRP Baseline load forecast; the technical potential of these demand side resources can be much greater under an Electrification RMA load forecast.

Aurora Wholesale Electricity Price Forecast

This section describes the AURORA® (Aurora) software that City Light used to create the wholesale electricity price forecast for the 2022 IRP. Aurora, offered by Energy Exemplar, LLC, was initially released in 1997. It is commercial, off-the-shelf software used by many utilities, resource planners, and regulatory agencies for long-term planning.

The Aurora model contains a default database that includes the characteristics of load centers, generating resources and transmission networks throughout the region. The model simulates the operation of the market for electric power on the western grid.

The type of information in the default database that was updated by City Light staff includes, but is not limited to:

1. More specific details about City Light's generating resources
2. Regional coal plant (or other) retirement dates
3. New renewable project commencement dates
4. More details on regional generation capabilities,
5. Greenhouse gas emission and pricing rates
6. Clean and renewable energy policies
7. Operating reserve requirements
8. Natural gas prices and other fuel types

The model then draws on its database to simulate the electric power market using economic dispatch logic. The model stipulates that the resources with the lowest marginal cost will be dispatched first. Aurora forecasts future hourly demand at each load center, then applies its algorithms to economically dispatch resources to meet demand in every hour at every load center, subject to transmission availability. The result is an hourly local market clearing price equal to the marginal cost of the last resource dispatched.

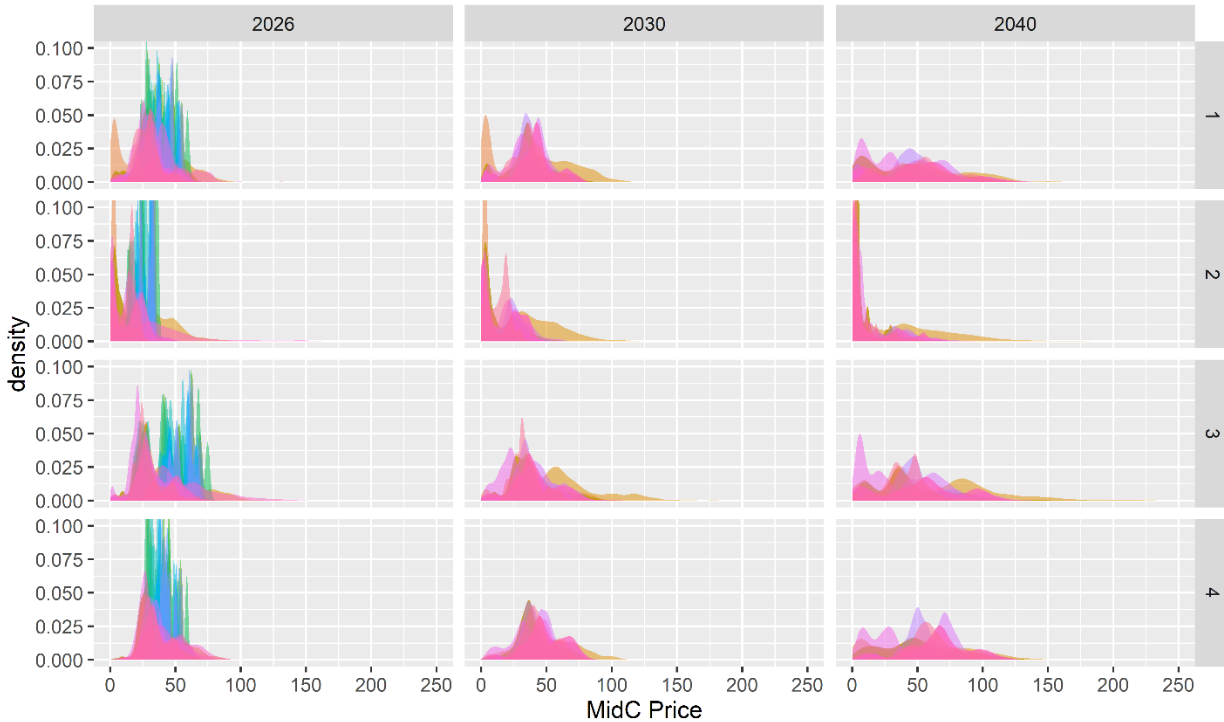
Other Wholesale Electricity Price Forecasts

City Light typically uses three different northwest electricity price futures or forecasts: Aurora and two 3rd party forecasts (from now on, referred to as TP1 and TP2). Aurora and TP2 forecasts produce variations on the forecast, such as a high and low forecast or a no federal carbon tax forecast. Each forecast is produced and delivered in a specific month. For example, TP2 is delivered in January, June, and November and produces an hourly forecast going forward about 30 years. TP1, on the other hand, is delivered every day (City Light uses the median of every set of transactions delivered that month) and produces future price transactions for the Heavy Load Hour (HLH) price and Light Load Hour (LLH) price for each month starting the month it is delivered and going forward about eight years.

Each time a new forecast is produced, the price distribution changes. The distribution is also very different when comparing the forecasts from each party. Some are more similar than others but seeing all the distributions together shows some of the variability in the northwest, or Mid-Columbia (MidC), price forecasts.

In Figure 1, the distributions of MidC prices are shown by year (2026, 2030, 2040) and quarter for all forecasts City Light received in 2021. Note that the TP1 transactions only go through 2029, so are only included in the 2026 distributions.

Figure 1 Distribution of MidC Prices By Year and Quarter



Some forecasts have a single peak with a common MidC price. Others have multiple peaks and are more evenly distributed between the range of prices. The peaks also occur at higher prices, or the prices are more evenly distributed in later years. Additionally, Q2 has a majority of prices forecasted to be low compared to the other quarters. The TP1 prices also produce a higher peak than Aurora and TP2 in 2026. Overall, there is a lot of variability between the 12 TP1 transaction periods, five Aurora forecasts, and six TP2 forecasts.

Figure 2 includes many delivered forecasts that City Light does not use for general use. Instead, City Light focuses on the median TP1 prices, the Aurora median forecast, and the base TP2 forecast. The variability between these can be viewed by looking at the distributions of these prices/forecasts that are produced in the same month. Figure 2 and Figure 3 below show the median/base prices/forecasts produced in January and June 2021.

Figure 2 Distribution of January 2021 MidC Prices By Year and Quarter

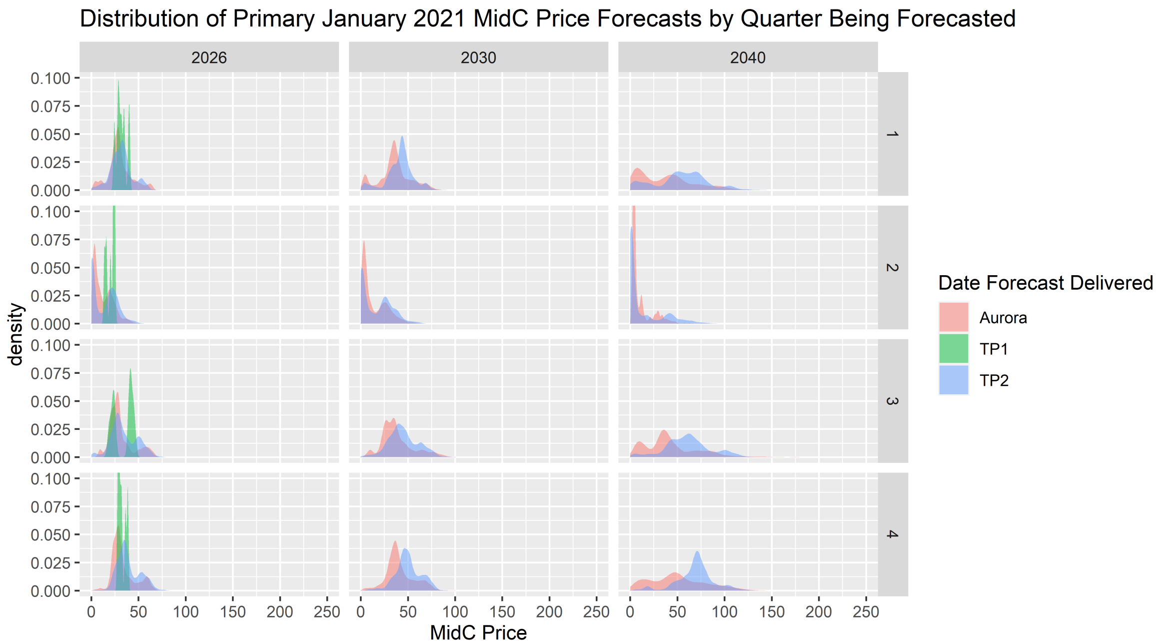
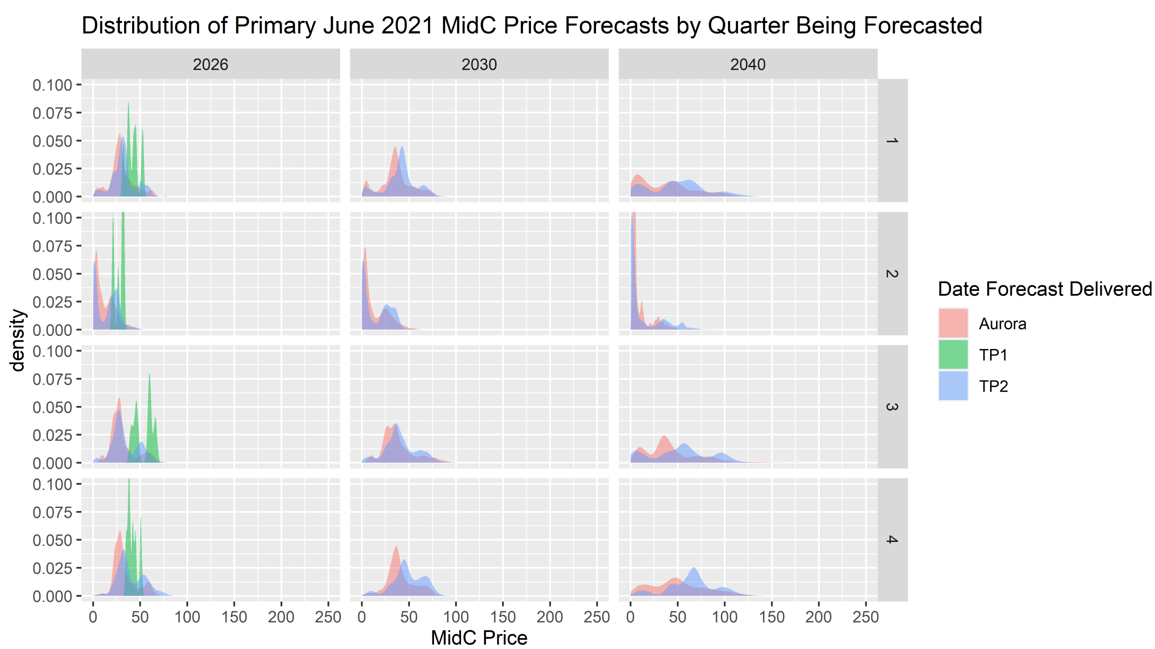


Figure 3 Distribution of June 2021 MidC Prices By Year and Quarter

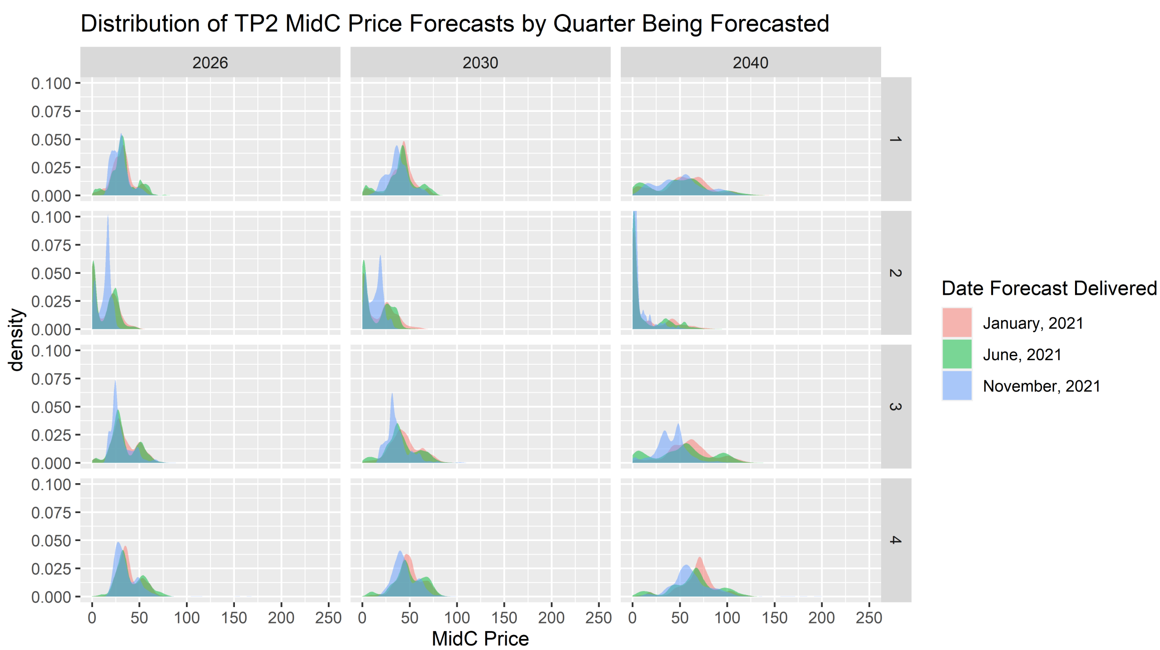


The TP1 prices have a much more narrow and jumpy distribution due to only producing HLH and LLH prices. Additionally, the TP2 peaks tend to be at a higher price than

Aurora's, although the general distribution for both forecasts are very similar. This is especially true in quarters 3 and 4.

While the variability between forecast models is interesting, the changes made by the same model between the months it is delivered shows how much when the forecast is produced impacts the forecast. Figure 4 below explores this by including the three base forecasts made by TP2 in 2021.

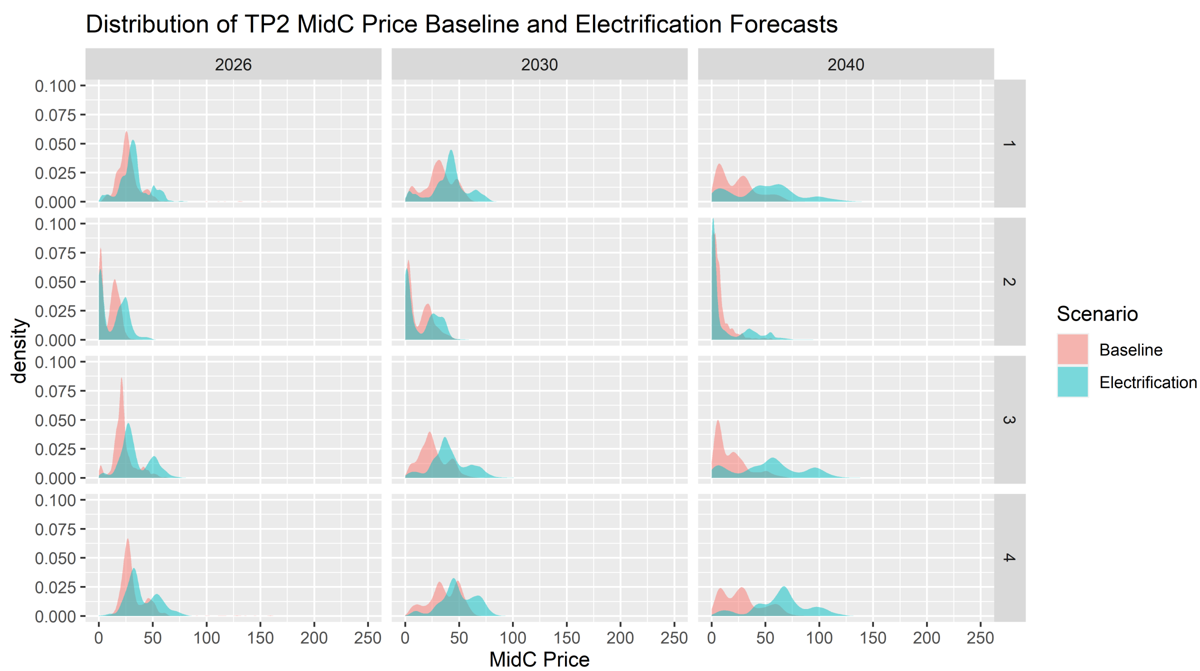
Figure 4 Distribution of TP2 MidC Prices By Year and Quarter



The January and June forecasts produced by TP2 are similar, but the November forecast has peaks at a visibly lower price. In Q2, the November forecast has a single peak for 2026 and 2030 that lies between the two peaks produced by the other forecasts. The largest differences between the distributions are in 2040, which is harder to forecast because it is the farthest in the future.

Electrification will also have a large impact on MidC prices. The TP2 created a June 2021 forecast used by City Light for its electrification analysis. Figure 5 below compares this forecast to the baseline delivered in the same month and year.

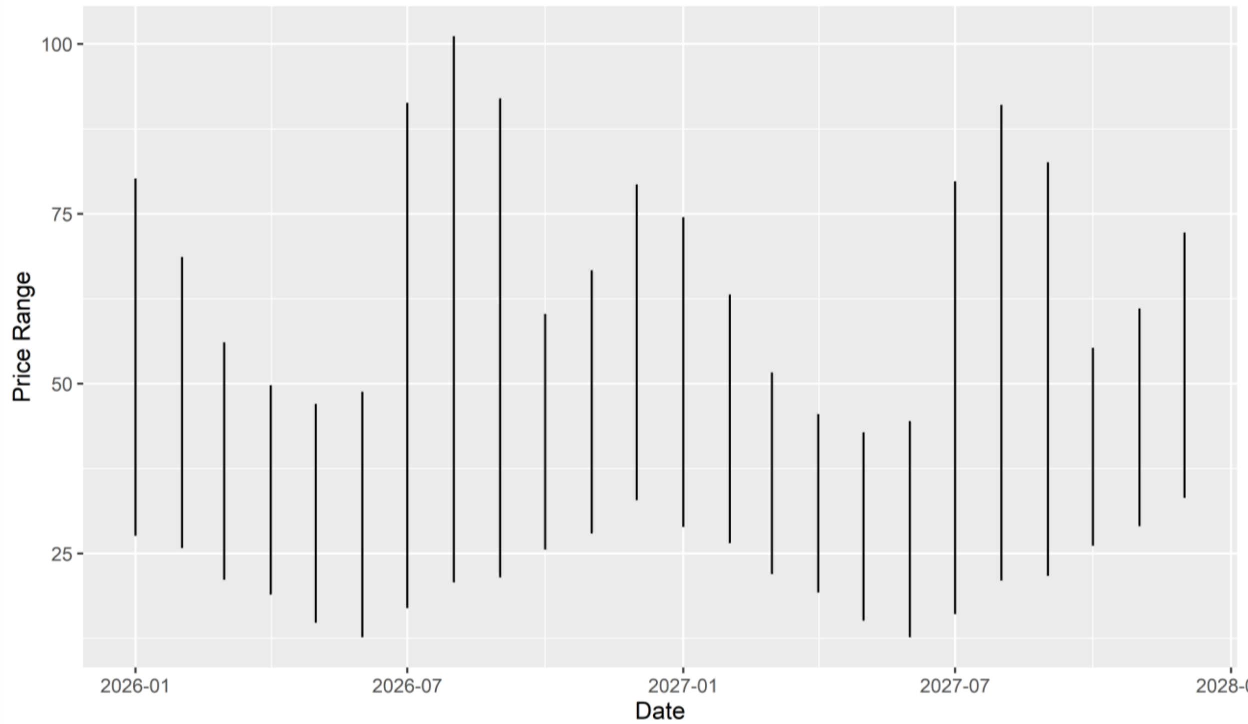
Figure 5 Distribution of TP2 MidC Price Forecasts for Baseline and Electrification by Year and Quarter



The distributions for the electrification forecast are shifted to the left, with the peaks at lower prices. The largest shifts are in 2040, as well as Q3 and Q4.

The distribution of price forecasts demonstrates the differences between forecasts, but each forecast also has a seasonality to it. All three forecast models have similar shapes, but Figure 6 uses the 2021 TP1 prices to both demonstrate the seasonality as well as the range of prices for each month.

Figure 6 Monthly MidC Price Forecast Seasonality and Range 2026-2027

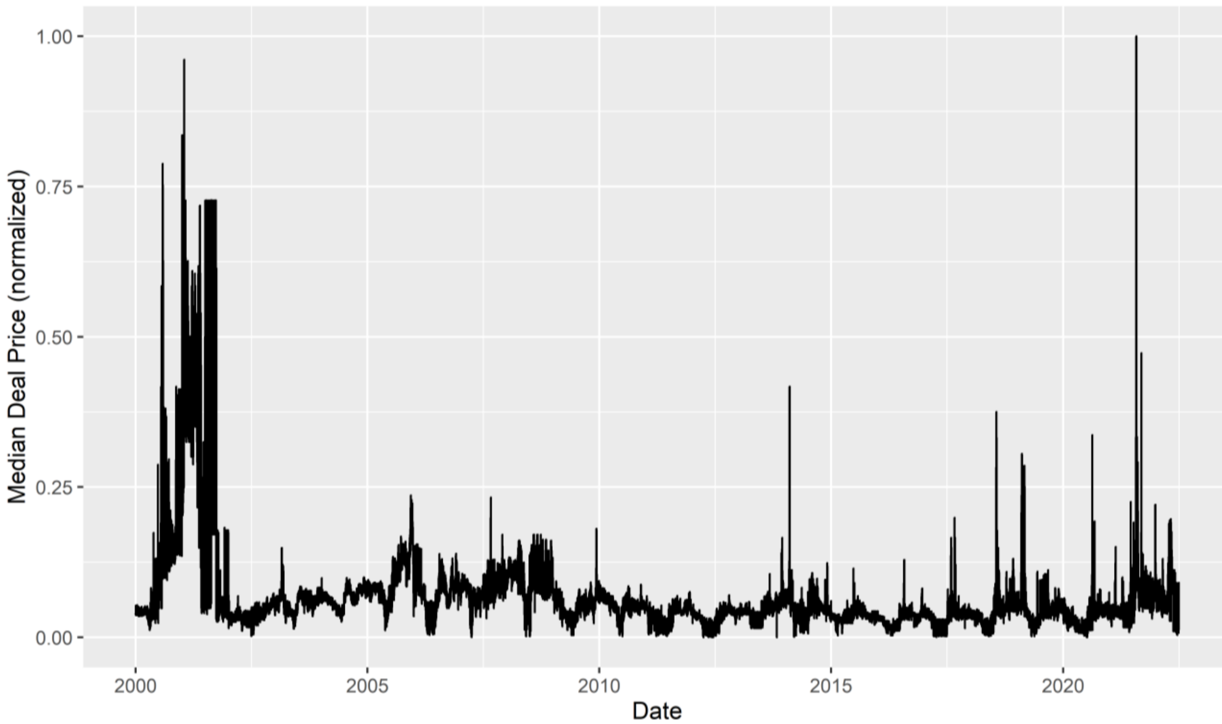


The highest MidC prices in Figure 6 in 2026 and 2027 are in July, August, and September, with an additional winter peak in December. The summer peak also includes the widest range of forecasted prices.

Historical Wholesale Electricity Price Transactions

Since a majority of transactions go through MidC, the price of historical transactions becomes a fair approximation of the actual MidC price at that time. Figure 7 details median hourly value of the deal price of each historical transaction, with values normalized to be between 0 and 1.

Figure 7 Historical Median Hourly Value of Deal Price



There has been a lot of variability over the years, as shown in Figure 7. This variability started with the energy crisis in 2000-2001 and decreased until about 2010. There was very little variability in deal price after 2010 until the pandemic hit.

Table 1 Historical Weighted Average Hourly Value of Deal Price Statistics Every 5 Years

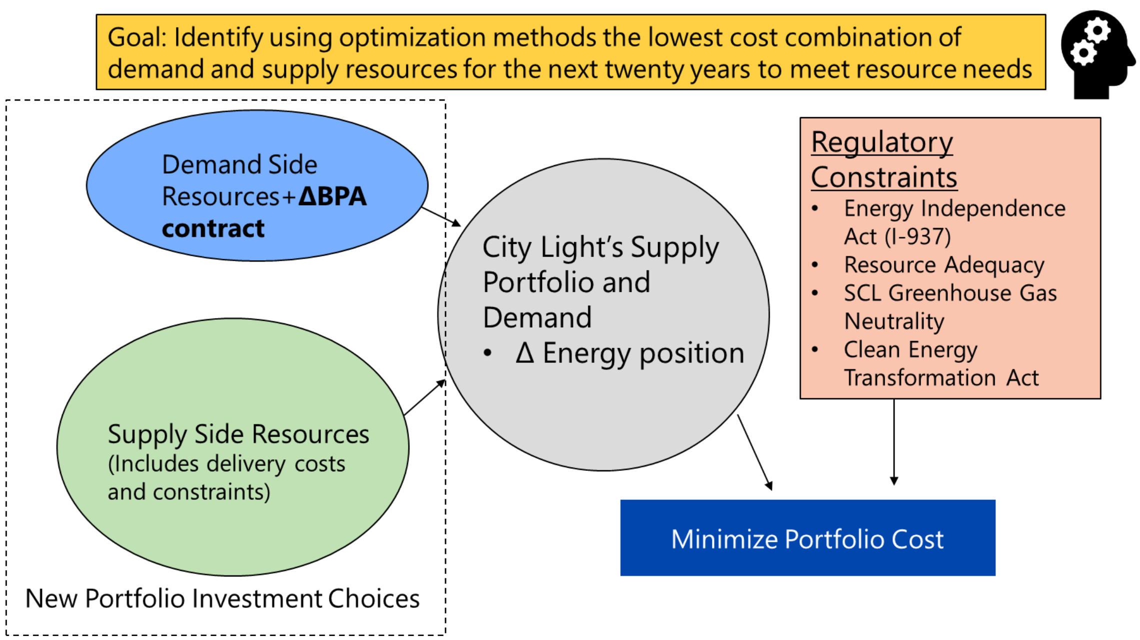
Year	Mean	Standard Deviation	Skew
2000	71.92	79.03	2.19
2005	50.41	18.88	0.42
2010	28.97	11.36	1.32
2015	25.66	18.78	11.91
2020	34.12	23.46	4.94

Similarly to Figure 7, Table 1 shows that variability is starting to increase, but it is not as bad as the 2000s. In addition, the skew shows that extreme prices are occurring more frequently and consistently as compared to the early 2000s.

Seattle Area Resource Additions Advisor (SARAA) Capacity Expansion Model

SARAA is a capacity expansion mixed-integer linear program that is used to complete the 2022 IRP framework. This framework builds a portfolio which meets the requirements of City Light's needs for the period of 2022 to 2041 for a specific scenario. The goal of SARAA is to minimize total portfolio costs while ensuring that City Light's portfolio requirements are met. SARAA's framework is summarized in Figure 8.

Figure 8 2022 IRP Portfolio Framework



SARAA assesses both supply and demand side options, as these options have unique contributions to portfolio needs that are summarized under the Regulatory Constraints in Figure 8. Each of the components of this framework are broken down in sections of other appendices.

Once the first portfolios are created with the expected conditions outlined in either the 2022 IRP Baseline or Electrification RMA scenario, additional portfolio strategies are created based on stress testing policies, learnings from portfolio runs, and advisory group feedback. In the creation of portfolio strategies, a starting condition is changed such as an assumption, input, or policy constraint while ultimately still meeting the regulatory constraints during the 20-year IRP window. For example, one portfolio strategy looked at turning the I-937 constraint "off" to measure the impact of this policy on total resource additions and total portfolio costs.

For the 2022 IRP Baseline scenario, Table 2 shows 20 initial portfolio strategies that were created based on stress testing policies, risks, and advisory group feedback.

Table 2 2022 IRP Baseline Scenario 20 Portfolios

Portfolio Name	Solar (aMW)	Wind (aMW)	EE (aMW)	DR (aMW)	Customer Solar (aMW)
Lowest Cost	**64.38**	**118.68**	**115.93**	**0.00**	**0.00**
No I-937 Obligations	91.00	42.00	115.93	0.00	0.00
Unlimited Transmission & No I-937 Obligations	92.33	31.50	122.32	0.40	0.00
Unlimited Transmission	85.41	98.73	115.93	0.00	0.00
Includes 2DR	**57.72**	**130.23**	**115.15**	**17.52**	**0.00**
Includes 4DR	**57.72**	**130.23**	**115.93**	**19.03**	**0.00**
BTM Solar 1x RECs	50.80	129.18	123.09	1.47	7.28
BTM Solar No REC Value	50.80	129.18	128.08	0.00	7.28
BTM Solar 2X RECs	50.80	129.18	123.09	1.47	7.28
Balanced	**50.80**	**117.62**	**115.93**	**17.52**	**7.28**
2030 GHG Free with Low Water	92.33	378.00	115.93	0.00	0.00
No New Resources Until 2029	43.88	140.73	115.93	0.00	0.00
Early RA Needs	57.72	128.12	106.55	0.00	0.00
2032 Electrification RMA Loads Begin	**91.26**	**464.91**	**115.93**	**1.86**	**0.00**
Balanced BPA Impacted by BTM Solar	50.80	117.62	115.93	17.52	7.28
Balanced Alternative	57.72	130.23	115.93	17.52	7.28
Early Overbuild	57.72	283.50	115.93	17.52	0.00
Electrification RMA Derived High EE	**50.80**	**129.18**	**149.89**	**0.00**	**0.00**
Solar + Battery Alternative	45.63	139.68	114.29	0.00	0.00
Solar + Battery	**45.63**	**139.68**	**115.93**	**0.00**	**0.00**

Most of the portfolios in Table 2 show that the top two resources of choice are supply side wind and demand side energy efficiency, followed by supply side solar, then demand side demand response and customer solar. The portfolios highlighted in bold are the top seven portfolios which are discussed in detail in Appendix 5: Create Top Portfolio. These portfolios were picked as top portfolios as they showed unique and diverse strategies, as well as based on input from the external IRP advisory panel.

The 2022 IRP Baseline scenario high level portfolio conclusions include:

1) The portfolio builds are mainly driven by August resource adequacy need and I-937.
2) Transmission and I-937 constraints limit the value of demand response programs and solar supply resources.
3) Montana wind is chosen in 2030s solely for I-937 needs.
4) Most of the portfolios contain slightly more commercial EE savings compared to the 2022 Conservation Potential Assessment (CPA).
5) CETA's compliance strategy can be achieved by current resource adequacy strategy under median hydro conditions.
6) Portfolios fall short under climate change and electrification scenarios.

For the Electrification RMA scenario, eight portfolio strategies were created based on stress testing policies, risks, and advisory group feedback. The Electrification RMA scenario is an aggressive electrification plan and serves as a bookend for analysis and learnings about attributes that can be important for electrification in the future. Table 3 shows these eight strategies.

Table 3 Electrification RMA Scenario Eight Portfolios

Portfolio Name	Solar (aMW)	Wind (aMW)	EE (aMW)	DR (aMW)	Customer Solar (aMW)
Lowest Cost	30.04	591.57	149.89	0.40	0.00
With 2022 IRP Baseline Lowest Cost	64.38	560.07	149.89	17.52	0.00
With 2022 CPA Baseline	91.26	464.91	149.89	1.86	0.00
With 2022 IRP Baseline Solar Builds	64.38	560.07	149.89	17.52	0.00
Includes 4DR	30.04	581.07	149.89	19.03	0.00
No December RA Need past 2032	50.80	403.23	138.80	17.52	0.00
No RPS	30.04	581.07	149.89	17.52	0.00
No winter RA need before 2032	71.56	485.91	144.13	0.40	0.00

Table 3 shows the portfolio strategies for the Electrification RMA scenario. All the portfolios favor supply side wind as the top resource of choice, followed by demand side energy efficiency, supply side solar, demand side demand response, and customer solar. None of these portfolios were picked as top performing portfolios for this 2022 IRP, as all of them could not meet the transmission constraints while fulfilling City Light's portfolio resource needs.

The 2022 IRP Electrification RMA scenario high level portfolio conclusions include:

1) The current transmission constraints cause City Light to be unable to meet the electrification loads under this scenario.
2) Portfolio cost is at least doubled for all RMA portfolios compared to the 2022 IRP Baseline scenario.
3) Portfolio builds favor resources that can help meet the December resource adequacy needs.
4) Solar resources fall short in meeting high winter loads and needs.

5) Seattle needs its maximum BPA entitlement for reliability and meeting clean energy requirements as early as 2030 independent of aggressive energy efficiency.
6) Demand response is attractive, and energy efficiency potential under electrification loads needs to be studied; winter programs are important for electrification.

APPENDIX 5: CREATE TOP PORTFOLIO

As part of the 2022 IRP, three scenarios were considered:

- 2022 IRP Baseline (i.e., 2020 corporate load forecast) with historical water supply and historical temperature,
- Climate change with simulated water supply and simulated temperature, and
- EPRI's Rapid Market Advancement (RMA) Electrification load forecast with historical water supply and historical temperature.

For the development of a top portfolio in the 2022 IRP, the 2022 IRP Baseline scenario attributes were used. The climate change and electrification RMA scenarios were used as scenarios to help understand if different portfolios have attributes that could help with uncertain futures.

Over 20 different portfolios were initially considered and tested. All the initial portfolios contain one or more of the IRP strategies in Figure 1.

Figure 1 Portfolio Strategies in 2022 IRP

The portfolio number was reduced to seven after several initial assessments were completed. One initial assessment included ensuring all portfolios met the transmission constraints for the supply resources. The '100% Clean by 2030' strategy was designed to build a mix of resources that would have no greenhouse gas emissions by 2030. This strategy resulted in a substantial need for supply resources, wind in particular, which violated projected transmission constraints. Therefore, the '100% Clean by 2030' strategy was not represented in the final seven top portfolios. The 'Resource Adequacy Risk Reduction' strategy also featured portfolios violating transmission assumptions, so this strategy was not represented in the final seven top portfolios either.

The second initial assessment included making sure that all possible portfolios could be compared across portfolio metrics. It became clear that the 'Transmission Availability' strategy resulted in much different portfolio composition. In other words, because all the transmission constraints were relaxed in the 'Transmission Availability' strategy, portfolio costs were significantly lower. This made a portfolio with no transmission constraints not comparable to the others with transmission constraints. The 'Transmission Availability' strategy was not represented in the final seven top portfolios either.

A 'Battery Storage' strategy was added during portfolio analysis based on the external advisory panel input. If any portfolio strategies were represented multiple times, the lowest cost strategy was chosen. These seven top portfolios align with the latest regional transmission assumptions, state and local clean energy policies, and City Light's resource adequacy metrics and resource options.

Top Seven Portfolio Facts:

- All seven portfolios are built to meet resource adequacy needs under the baseline scenario with the metric of 0.2 monthly loss of load event, which is equivalent to two 'bad events' every 10 years for each January, July, August, and December months. These months were chosen as they represent traditionally challenging load coverage time periods. A 'bad event' is a situation in which all City Light's energy resources (i.e., contracts + owned generation + 200 MW market reliance), for all weekdays of all calendar months except July and August, cannot meet a system-wide net energy deficit lasting more than four consecutive hours, or as a system-wide net energy deficit event lasting four or fewer consecutive hours and for which at least one hour is more than 200 MW deficit[3].
- All portfolios meet I-937 policy requirements and Clean Energy Transformation Act requirements under baseline hydro median conditions.

[3] this assumption was determined through interviews with City Light Power Marketing Operations and System Operations Center staff where our hydro flexibility is assumed to be able to meet deficits for this length of time

- Six of the seven portfolios are within 3.1% Net Present Value costs of each other.
- None of the portfolios adequately achieve the resource adequacy metric of 0.2 monthly loss of load event under climate change scenarios and are much less adequate under the rapid market electrification scenario. However, both the climate change and electrification scenarios have preliminary assumptions that need further exploration.
- All of City Light's portfolios are greater than 90% clean from an emissions perspective under hydro median water conditions.
- Customer programs (i.e., demand response, energy efficiency, and customer solar) are a meaningful factor in differentiating portfolios, especially if the climate change and electrification scenario uncertainties are considered.
- For the 2022 IRP, the top seven portfolios are identified and described in Table 1.

Table 1 2022 IRP Top Seven Portfolio Names

Portfolio	Description
P1: Lowest Cost	Base Lowest Cost
P6: 2DR	Base Lowest Cost + 2 Demand Response
P7: 4DR	Base Lowest Cost + 4 Demand Response
P11: Balanced	Base Lowest Cost + 2 Demand Response + Customer Solar
P34: 2032 Elect	Base Lowest Cost + 2032 Electrification RMA Loads Begin
P35: High EE	Base Lowest Cost + High Energy Conservation
P36: Solar + Batt	Base Lowest Cost + Utility Scale Solar with Battery

These portfolios bring incremental utility scale supply resources in MW as shown in Table 2.

Table 2 2022 IRP Top Seven Portfolio Supply Additions (MW)

Portfolio	2024	2026	2027	2032	2033	2034-2041	Total
P1	100	300	25	75			500
P6	100	275	25	75	25		500
P7	100	275	25	75	25		500
P11	100	300		25	25		450
P34	100	300	100	325	250	550	1,375
P35	100	300					475
P36	100	300	25	75			500

The top seven portfolios all have slightly greater energy efficiency forecasts than the 2022 Conservation Potential Assessment and the 2022 Clean Energy Implementation

Plan. Table 3 provides each portfolio's cumulative energy conservation resources in aMW.

Table 3 2022 IRP Top Seven Portfolio Energy Efficiency Incremental Additions (aMW)

Portfolio	2025	2031	2041
P6	39	84	115
P1, P7, P11, P34, P36	39	85	116
P35	44	101	150

The top seven portfolios have cumulative customer solar resources in MW as shown in Table 4.

Table 4 2022 IRP Top Seven Portfolio Customer Solar Incremental Additions (MW)

Portfolio	2025	2031	2041
P11	14	29	52
P1, P7, P11, P34, P35, P36	0	0	0

The assumed customer solar resources would be in addition to programs currently available, with incremental additions up to 52 MW capacity by 2041. A new program with a goal of rapid incremental growth in customer solar capacity would likely target a variety of customer types, center equitable access to renewables, and may require legislative action to appropriately incentivize. Synergies and complementary benefits may be found with programs incorporating storage solutions, demand response, and ongoing transportation electrification efforts.

These portfolios have cumulative demand response potential in MW as indicated in Table 5.

Table 5 2022 IRP Top Seven Portfolio Demand Response Incremental Additions (MW)

Portfolio	DR Programs	2025	2031	2041
P1, P35, P36	Nothing	0	0	0
P34	Residential Thermostat Residential Heat Pump Water Heating	4	44	59
P6, P11	Residential Thermostat Residential Electric Water Heating	10	88	122
P7	All DR Programs[4]	13	104	141

Introduction to Portfolio Metrics

The portfolios are looked at according to six different metrics. These metrics are part of the 2022 IRP process to account for costs (Net Present Value), the climate change scenarios studied (Climate Change impacts), portfolio unspecified purchases (Greenhouse gas emissions), diversity of customer options (Expanded customer programs opportunity), the Electrification RMA scenario studied (Electrification preparedness), and transmission cost and uncertainty (Transmission risk). All these metrics are equally weighted.

Net Present Value: The net present value is reported in 2021 real dollars (in billions$). Net present value contains the sum of all portfolio costs for resources (e.g., supply, energy conservation, demand response, customer solar, renewable energy credit purchases), BPA block power contract, social cost of greenhouse gas, and net wholesale revenue from 2022 to 2041. The net present values for the top seven portfolios are shown in Table 8 of the Conclusions section.

[4] P7 features four DR programs: Industrial/Commercial Curtailment, residential thermostat, residential electric resistance water heating, & residential heat pump water heating

Figure 2 2022 IRP Top Seven Portfolio Annual Portfolio Costs

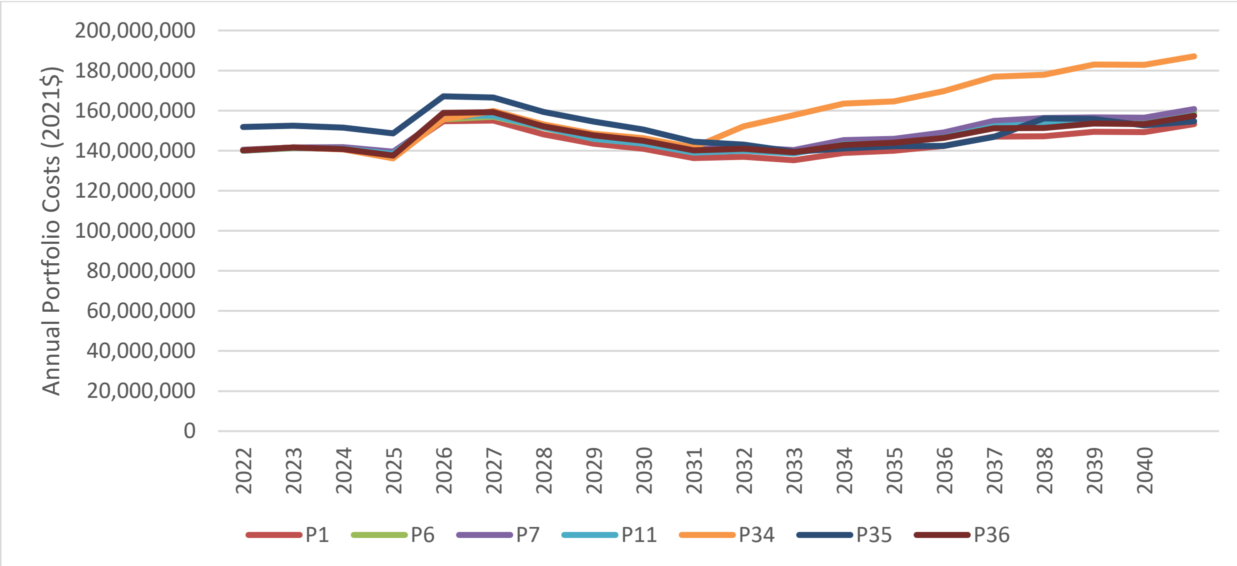


Figure 2 shows the annual net portfolio costs of the top seven portfolios, that are a part of the net present value calculation. P35 has high annual costs prior to the 2030s due to the higher conservation programs associated with this run (this energy efficiency program path was identified as the preferred path under the Electrification RMA scenario). P34 is a portfolio influenced by higher electrification loads starting in 2032. The rest of the portfolios follow similar patterns and very similar net present value costs, including P1 or the lowest portfolio with builds in the 2020s for resource adequacy, and some builds in the 2030s for I-937 compliance.

Climate Change: The climate change metric measures the mean of each climate change portfolio monthly loss of load event metric for the months of January, July, August, and December for the years 2030 and 2040. Two global climate models, CanESM2 and CCSM4, are selected to represent the changing temperature effects on load and hydrology effects on supply. These two models best represented future variability rather than the average climate change projections. The mean monthly loss of load event metric is the average of each of the two years and two models. It is important to mention that both CanESM2 and CCSM4 have well recognized periods of wintertime cold bias (i.e., colder than observations) in their Seattle temperature projections. This in turn would also bias how these portfolios' resources meet (or do not meet) the Seattle wintertime loads associated with these climate models.

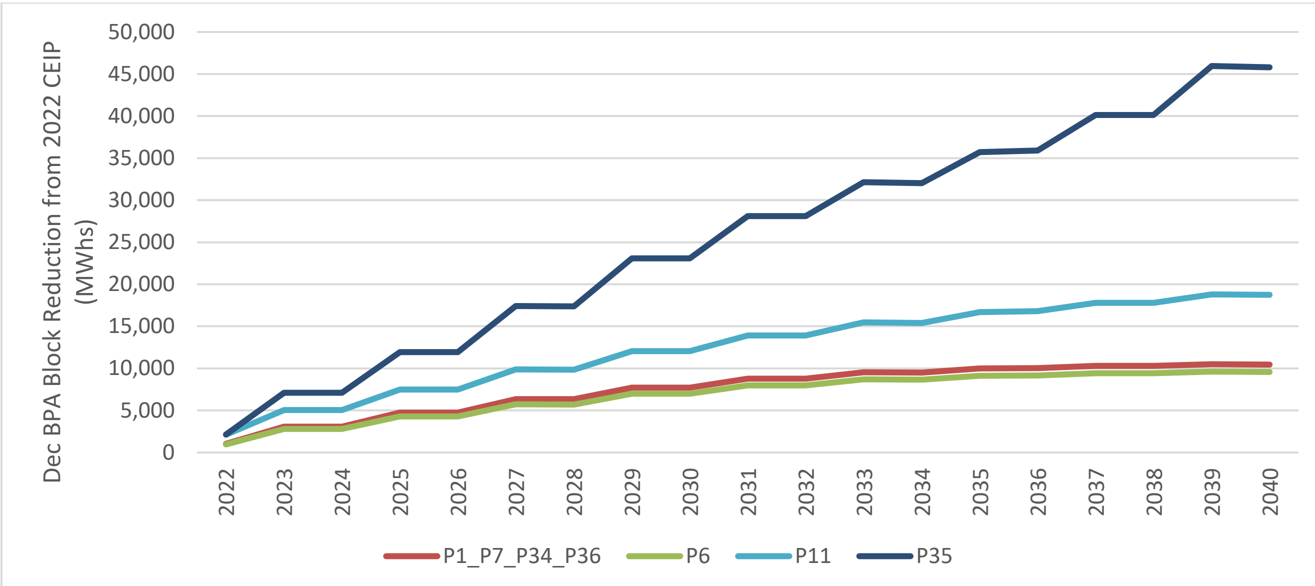
Table 6 2022 IRP Top Seven Portfolio Performance Under Climate Change Scenarios CanESM2 & CCSM4 Models

Portfolio	Description	Mean MoLOLEV
P34	Base Lowest Cost + 2032 Electrification Loads Begin	1.45
P11	Base Lowest Cost + 2 DR + Customer Solar	2.48
P7	Base Lowest Cost + 4 DR	2.48
P6	Base Lowest Cost + 2 DR	2.56
P36	Base Lowest Cost + Utility Scale Solar with Battery	3.13
P1	Base Lowest Cost	3.17
P35	Base Lowest Cost + High Energy Conservation	3.17

From Table 6, a smaller distance means greater resource adequacy performance. For example, 1.27 distance for P34 means that its loss of load event was ~1.5, which is well above the 0.2 loss of load event target. Given that all the distance measurements are greater than zero, none of the portfolios can perform at the current resource adequacy metric of 0.2 loss of load event in a climate change future. P34 performs the best of all the portfolios, due to it having the most resources in its portfolio, so it would be much better positioned to absorb the increased loads and altered stream flows as a result of climate change.

P11, P6, and P7 are the next best (these portfolios have similar conservation and demand response programs), the rest of the portfolios perform the worst. It is important to note that energy efficiency and customer solar reduce electricity load, which may in turn reduce our annual Bonneville Power Administration (BPA) allocation. This is especially true in in the wintertime, which is when City Light receives the most energy from its BPA block contract.

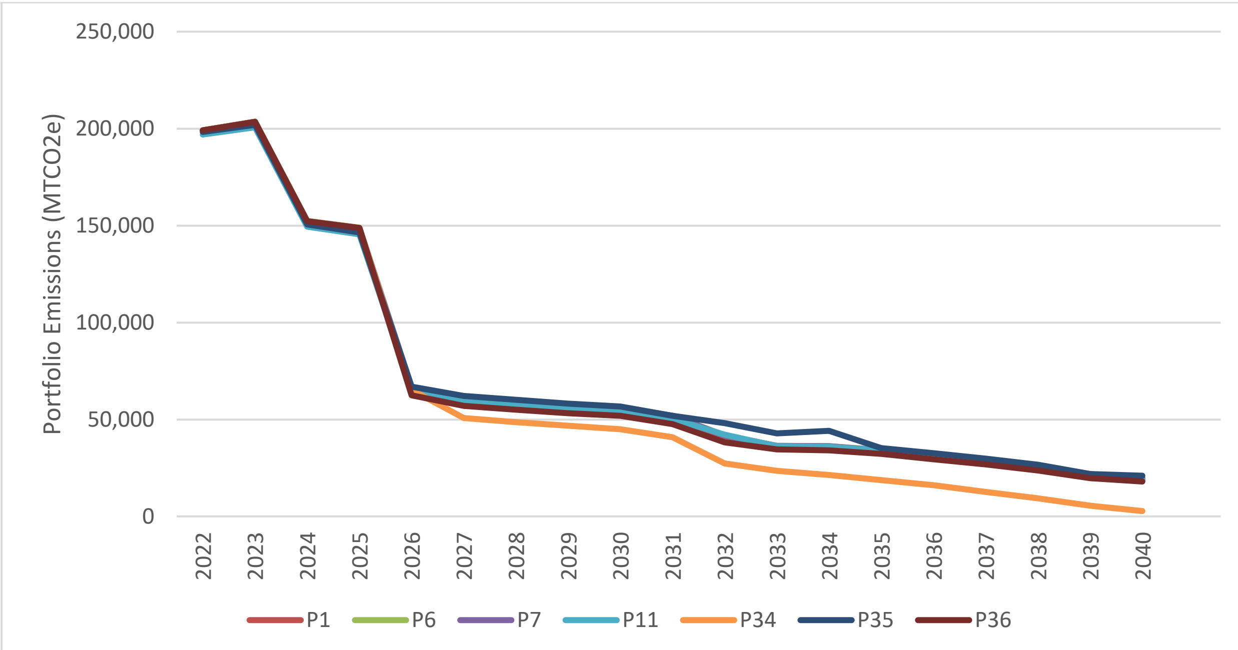
Figure 3 2022 IRP Top Seven Portfolio December BPA Block Reductions Compared to the 2022 Clean Energy Implementation Plan



The December BPA Block in Figure 3 is a reduction compared with the 2022 Clean Energy Implementation energy efficiency path. It shows that all the seven portfolios use a higher energy efficiency forecast and/or customer solar value compared to the 2022 Clean Energy Implementation Plan, which reduces the BPA block allocation in December. This can be a risk for City Light, especially for portfolios P11 and P35, because the electrification scenario shows more resource adequacy needs in the winter months. For this reason, the 2022 IRP assumes that the customer solar incremental additions shown in Figure 3 do not reduce the BPA block contract. In other words, the customer solar program will behave like a supply side resource where customer participation can be tracked and accounted for.

Emissions: The emissions metric calculates the total metric tons of carbon dioxide equivalent from 2022 to 2041 for any given portfolio.

Figure 4 2022 IRP Top Seven Portfolio Unspecified Purchase Emissions in Metric Tons of Carbon Dioxide Equivalent



A portfolio's total emissions of Metric Tons of Carbon Dioxide Equivalent ($MTCO_2e$) in Figure 4 includes three sources of emissions: emissions from unspecified market purchases, emissions from non-BPA power contracts, and emissions from the BPA power contract. Any source of unspecified power is assigned an emissions rate of 0.437 $MTCO_2e$ per MWh, which is the emissions rate specified in the Clean Energy Transformation Act.

P34, despite its significant quantity of clean resources as compared to the other portfolios, does not result in significant reductions in emissions. This is because the BPA block contract is the more significant source of emissions post-2026 and is always brought to load. However, it is assumed that City Light's BPA block contract has a 100% emissions free option available starting in 2040. For the 2022 IRP, there are no assumed specified clean market purchases in the event of a City Light energy shortfall. In other words, any market purchases needed to meet load will be from unspecified power sources.

Customer Programs: A customer program metric was created to measure each portfolio's ability to carry out City Light's vision of providing more flexibility in how customers can meet their energy needs, and to further advance equitable community connections. Furthermore, the Washington State Clean Energy Transformation Act specifically emphasizes equitable customer involvement in a clean energy future. The customer program metric considers the number of customer programs available in each of the seven IRP top portfolios. The number of demand response options available, the amount of energy efficiency programs, and customer solar are all factored into this metric and are identified for each portfolio as depicted in Table 7.

Table 7 2022 IRP Top Seven Portfolio Count of Demand Response, Energy Efficiency, and Customer Solar Program Options

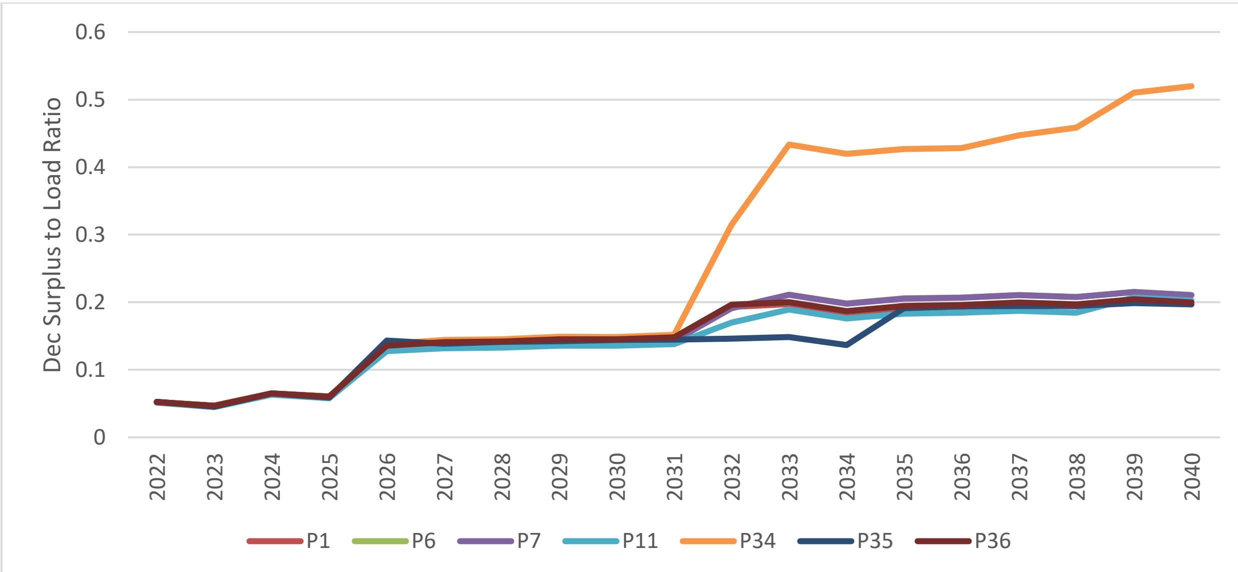
Portfolio	Demand Response # Programs (4 possible programs)	Energy Efficiency (23 possible programs)	Customer solar (1 possible program)
P1	0	16	0
P6	2	15	0
P7	4	16	0
P11	2	16	1
P34	2	16	0
P35	0	21	0
P36	0	16	0

The customer metric gives equal weight to energy efficiency, demand response, and customer solar programs, as defined:

$$\left(\frac{Demand\ Response\ Count}{4} + \frac{Energy\ Efficiency\ Count}{23} + \frac{Customer\ Solar\ Count}{1}\right) \div 3$$

Electrification: The electrification metric looks at how surplus/deficit the month of December is for each of the seven IRP portfolios. In other words, the net hourly surplus/deficit MWhs of City Light's resources as a fraction of the total MWhs of City Light's load for December. Recent electrification RMA studies show future building and vehicle electrification can increase City Light's load, especially in the winter, and most significantly in December.

Figure 5 2022 IRP Top Seven Portfolio Expected December Net Surplus Under Baseline Load Scenario



While the electrification metric only looks at the years 2030 and 2040, Figure 5 covers all years and details the December net position as a fraction of load for the years 2022 to 2040. P34, which is the portfolio that plans resource additions according to rapid market electrification loads starting in 2032, performs very well in the post 2032 years compared to the others in this category of metrics. Though none of the portfolios can meet the electrification RMA needs for *all* years from 2022 through 2041, P34 does meet the electrification needs starting in 2032 until 2041.

The electrification metric is:

$$\left(\frac{Dec\ Net\ Position\ 2030 + Dec\ Net\ Position\ 2040}{Dec\ Net\ Load\ 2030 + Dec\ Net\ Load\ 2040}\right)$$

Transmission: The transmission metric looks at the total estimated cost of transmission in each of the seven IRP portfolios. Due to uncertainty in future transmission capacity, this metric can not only serve as a cost metric for transmission for the portfolios, it can also be viewed as a transmission risk level for each of the portfolios.

Figure 6 Top Seven Portfolios Annual Transmission Costs

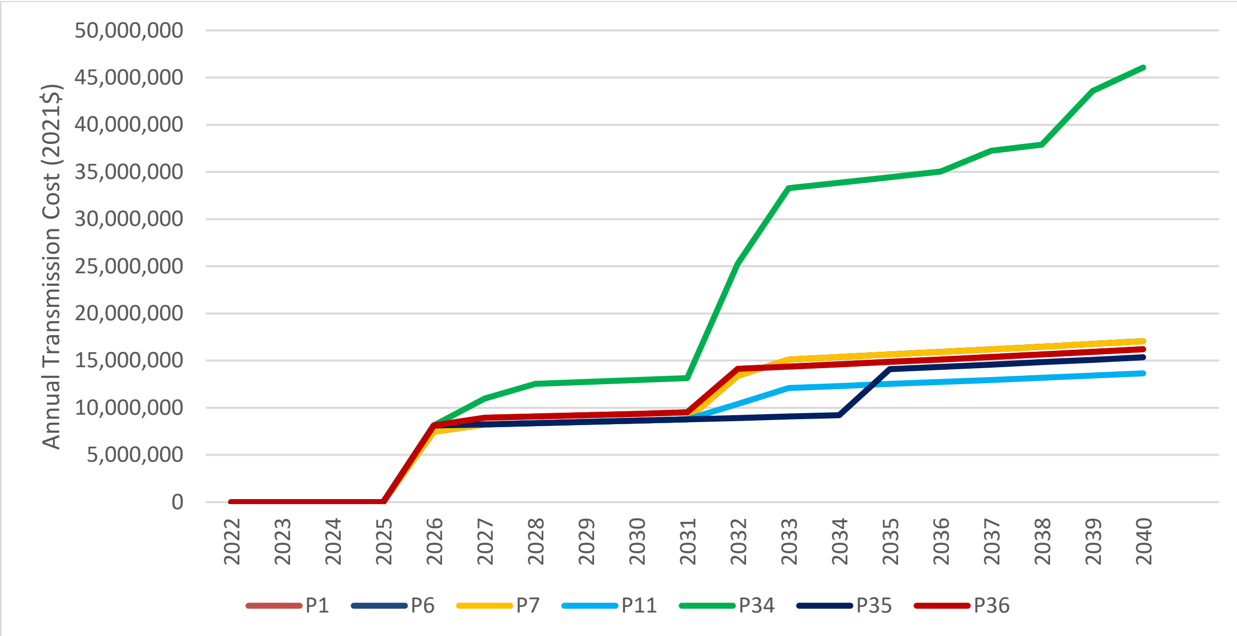


Figure 6 shows how P34, which is the portfolio that plans resource additions such as Montana and Offshore wind according to electrification RMA loads starting in 2032, has a lot of transmission costs. Rapid electrification aside, P11 and P35, which rely more on local and demand side resources, do not have as much exposure to transmission costs over time.

Conclusions

A summary of the performance of the seven top portfolios across all the metrics is shown in Table 8. The heat map coloring is used to indicate the relative performance of different portfolios for each metric; green is better performing than red.

Table 8 2022 IRP Top Seven Portfolio Metric Performance Heat Map

Portfolio	NPV (bil$)	Climate	SCL_MTCO2e	Customer	Electrification	Transmission (bil$)
P1	2.83	3.17	1,407,960	0.2	0.17	0.23
P6	2.88	2.56	1,447,275	0.4	0.18	0.24
P7	2.90	2.48	1,445,311	0.6	0.18	0.24
P11	2.90	2.48	1,448,246	0.7	0.17	0.19
P34	3.87	1.45	1,160,274	0.4	0.34	0.59
P35	2.90	3.17	1,460,613	0.3	0.17	0.22
P36	2.92	3.13	1,396,117	0.2	0.17	0.23

Table 9 2022 IRP Top Seven Portfolio Strengths and Weaknesses

Portfolio Name	Strengths	Weaknesses
P1: Lowest Cost	• Lowest cost portfolio	• No demand response programs or customer solar resources • Lowest RA performance under climate change or electrification scenarios
P6: Base Lowest Cost + 2 DR	• Includes 2 highest potential demand response programs • Good customer optionality	• 1.7% more costly compared to P1 • Doesn't adequately meet resource adequacy under climate change or electrification scenarios
P7: Base Lowest Cost + 4 DR	• Includes all 4 IRP demand response programs, • Provides 2nd most customer optionality	• 2.4% more costly compared to P1 • Includes 2 demand response programs that currently don't have much value • Doesn't adequately meet resource adequacy under climate change or electrification scenarios
P11: Base Lowest Cost + 2 DR + Customer Solar	• Includes 2 highest potential DR programs • Provides the most customer optionality • Lowest supply side transmission reliance	• 2.4% more costly compared to P1 • Doesn't adequately meet resource adequacy under climate change or electrification scenarios
P34: Base Lowest Cost + 2032 Electrification Loads Begin	• Meets resource adequacy metric for electrification RMA loads starting in 2032 • Performs the best under climate change scenario • Lowest emissions	• 27% more expensive compared to P1 • Relies heavily on uncertain wind transmission starting in 2032 • More than half of the portfolio composition by 2041 would be wind + solar renewables • Doesn't adequately meet resource adequacy under climate

Portfolio Name	Strengths	Weaknesses
		change or electrification scenarios before 2032
P35: Base Lowest Cost + High Energy Conservation	• Prepares for future electrification RMA loads by making large energy efficiency investments early • Plans on less supply side resources compared to P1	• 2.4% more expensive compared to P1 • Ignores demand response and customer solar programs • Lowest resource adequacy performance under climate change or electrification scenarios
P36: Base Lowest Cost + Utility Scale Solar/Battery	• Overbuilds summer resource adequacy with batteries paired with solar resources	• 3.1% more expensive compared to P1 • Ignores demand response and customer solar programs • Lowest resource adequacy performance under climate change or electrification scenarios

Table 10 2022 IRP Top Seven Portfolio Forecasted Resources Over the Next 20 years

Portfolio	Wind (MW)	Solar (MW)	EE (aMW)	DR (MW)	Added Customer Solar (MW)
P1	275	225	116		
P6	300	200	115	122	
P7	300	200	116	141	
P11	275	175	116	122	52
P34	1050	325	116	59	
P35	300	175	150		
P36	275	225	116		

Recommendation

City Light finds the portfolio attributes of P11 would be the best fit and the minimum in magnitude direction for the utility at the time of the 2022 IRP. It is recognized that circumstances could change, and City Light will continue to evaluate every two years whether its plans should be altered.

All the portfolios, aside from P34, score similarly in most of the metrics. City Light feels uncomfortable with recommending P34 because:

- the pace of electrification penetration assumptions is uncertain
- transmission assumptions associated with meeting electrification RMA loads are uncertain
- a City Light portfolio with a significant % of *only* wind and solar renewables (>50%) presents significant challenges to balance energy in real time
- future supply/demand resource technology could better fit future electrification needs in the 2030s

P1, P35, and P36 do not contain any demand response programs. Demand response programs add value as a tool for reducing climate change and/or electrification load uncertainties for both summer and winter, as well as minimizing financial impacts of wholesale power prices. At a customer level, it offers an important option in energy solutions. Therefore, City Light doesn't recommend portfolios P1, P35, and P36.

Portfolios P6, P7, and P11 all contain demand response programs. P6 and P11 contain two demand response programs: the residential thermostat program and the residential electric resistance water heating program. P7 contains two additional demand response programs (for a total of four programs): an Industrial/Commercial curtailment program and a residential heat pump water heating program, of which together only provide up to ~18MW of potential by 2041. The Industrial/Commercial curtailment program only has potential of up to ~11MW by 2041 and it is a summer peaking program, which isn't as valuable in an electrification scenario, where the biggest need is in the winter. The Industrial/Commercial curtailment program will not be a part of the demand response pilot program set to begin in January of 2023 due to low potential, high administration costs, and more limited equity value. Therefore, P6 and P11 are the two best portfolios with demand response to consider for the 2022 IRP.

The customer programs metric, which measures optionality for customers, is the one metric that creates the most differentiation among the two remaining portfolios, and it points to the P11 portfolio. P11 has both demand response programs and customer solar programs to further enhance resource diversity and less transmission reliance. The high potential demand response programs in P11 (residential thermostats and residential water heating) help the City Light portfolio to prepare for climate change and electrification uncertainties. Therefore, P11: Balanced portfolio is the 2022 IRP Top Portfolio.

APPENDIX 6: EQUITY, COMMUNITY OUTREACH, AND PUBLIC INVOLVEMENT PROCESS

City Light is proud to be a local, community-owned utility that is visible and actively involved in the communities it serves. Its commitment to racial diversity, social justice and the equitable provision of services to all is an important part of City Light's mission, vision, and values.

Equity

In 2021, City Light developed a Clean Energy Equity Plan (CEEP) to guide the utility's integration of equity into its planning, programs, and projects. The plan's goal was to support City Light in achieving an equitable transition to a 100% greenhouse gas-free, electric future in fulfillment of the objectives and intentions of the 2019 Washington Clean Energy Transformation Act (CETA).

With this in mind, the 2022 IRP introduced a new metric when helping to determine what mix of resources are best for meeting City Light's electricity demand over the next several years: the Customer Program Opportunities metric. This metric is one of six metrics designed to help narrow the top portfolio options down to one recommended portfolio to represent the 2022 IRP. As a result, the 2022 IRP portfolio of resources features more customer side attributes than in any previous Seattle City Light IRP to date. Examples of customer side resources include City Light sponsored energy conservation programs, demand response options in water heaters and/or thermostats, and customer/community solar projects. Customer programs not only reduce energy burdens, but also add to City Light's resource diversity. They keep dollars local and are energy investments in our community, creating green jobs for local contractors, retailers, consultants, and educators.

The forthcoming 2024 Demand Side Management Potential Assessment, expected to comprise of potential assessments for conservation, customer renewables, and demand response, is aiming to build on the 2022 IRP, and more specifically identify which customer side programs best support City Light's equity goals.

Community Outreach

In August 2021, City Light sought customer feedback on clean energy related topics for two main reasons. The first reason was to inform and help guide multiple strategic initiatives such as electrification, energy conservation, clean energy implementation, and integrative resource planning. The second reason was to follow guidance from the

Washington Clean Energy Transformation Act (CETA) to collect public comment and reflect this customer input in utility planning processes.

As part of the customer feedback process, a survey was conducted in which a total of 4,522 responses were gathered, including 633 respondents who self-identified as black, indigenous, or persons of color; 175 as Hispanic/Latino; 1,328 as renters; and 417 as having an annual household income of less than $50,000. The survey consisted of questions related to climate change, clean energy, electrification, and avenues of customer communication to City Light staff.

The survey demonstrated overwhelming concern among respondents about climate change, and the desire to reduce reliance on fossil fuels but still maintain affordable and reliable electricity.

Public Involvement Process

City Light's IRP process includes frequent interaction and information sharing with a panel of external IRP advisors. This external advisory panel consists of the following individuals:

- Steve Gelb, Emerald Cities Collaborative
- Paul Munz, Bonneville Power Administration (BPA)
- Jeremy Park, P.E. University of Washington
- Yuri Rodrigues, Seattle Pacific University
- Mike Ruby, Ph.D., P.E., Envirometrics, Inc.
- Joni Bosh, NW Energy Coalition
- Amy Wheeless, NW Energy Coalition
- John Fazio, NW Power & Conservation Council
- Elizabeth Osborne, WA Department of Commerce
- Kelly Hall, Climate Solutions
- Joanne Ho, Consultant

The City Light IRP team held nine, two-hour online meetings with this advisory panel from 2021 to 2022, shown in Table 1.

Table 1 2022 IRP External Advisory Panel Meeting Schedule

Date	Meeting Subject
January 29, 2021	2020 Progress Report Review, IRP Process Overview, Advisor Role and Feedback, Baseline Load Forecast updates, Planning for IRP Inputs/Scenarios/Timelines
March 30, 2021	Introduction to Conservation Potential Assessment, Demand Response Potential Assessment, Resource Adequacy, Resource Options
July 30, 2021	Clean Energy Transformation Act, Conservation Potential Assessment, Demand Response Potential Assessment, and Clean Energy Implementation Plan
November 8, 2021	Clean energy customer survey, equity indicators, introduction to climate change scenario
January 10, 2022	Resource adequacy, climate change scenario, EPRI electrification assessment summary, intro to 2022 IRP electrification scenario
February 14, 2022	Baseline and electrification scenarios, resource options, portfolio strategies
March 21, 2022	Initial portfolio options, introduction to portfolio metrics
April 11, 2022	Portfolio options and portfolio metrics
May 16, 2022	Final portfolio of resources and future work
June 17, 2022*	Mayor's office briefing of 2022 IRP
July 15, 2022*	Preliminary Seattle City Council briefing of 2022 IRP
July 27, 2022*	Seattle City Council briefing of 2022 IRP

*local governing body presentations

A few themes that came up during the feedback loop with the external IRP advisory panel include:

- Analyze risk of supply/demand resource development given current economics
- Ensure equity outcomes in demand/customer options program design
- Consider development of new energy technologies
- The City of Seattle should transition to electrification strategically

City Light takes external IRP advisory panel feedback seriously. For example, some additional analysis and sensitivities related to supply/demand resource development risk are part of the analysis in Appendix 8: Resource Adequacy.

City Light encourages members of the public to contact City Light if they would like to be considered for this panel.

APPENDIX 7: CLIMATE CHANGE

Introduction

This appendix provides more details about the climate change data used to perform the resource adequacy (RA) analysis using climate change scenarios as explained in Appendix 8: Resource Adequacy. The sections below describe the climate datasets for both assessing future temperatures effects on load and future streamflow impacts on hydropower supplies. Because there are numerous modeling datasets and limited capacity to perform climate change scenarios, the process of filtering representative scenarios down to two Global Climate Models (GCMs) is detailed. Additionally, the impacts on load and supply are explored.

Climate Datasets

Using the best available climate change data was essential to City Light's climate change analysis. Suitable datasets were identified from credible climate science that has be well vetted for the Pacific Northwest and offered the highest spatial and temporal resolution for local areas of interest to City Light. Identified datasets relied heavily on climate projections provided by the University of Washington Climate Impact Group (CIG). The CIG is an interdisciplinary research group at the University of Washington, and they provide the most rigorous and comprehensive climate change information for the Pacific Northwest for use in applications like this. Table provides a summary of the datasets gathered and used in the climate change analysis with additional details about these datasets provided below. All datasets use bias-corrected data, which supplies more accurate projections of temperatures and streamflows. Bias correction is the process of scaling climate model outputs to account for their systematic errors, in order to improve their fit to observations (Soriano et al. 2019).

Table 1 Summary of temperature and streamflow datasets used for climate change scenarios

Dataset	Description
SeaTac Temperatures	• Creator – University of Washington • Regional Climate Model – 12 GCMs • Dynamically downscaled with WRF – bias corrected • Simulations for 1970-2099 • Spatial resolution - 12 km • Temporal resolution - hourly
Skagit Streamflows	• Creator – University of Washington • DHSVM (hydrology model) – 10 GCMs • Statistically downscaled - bias corrected • Simulation for 1962-2099 • Spatial resolution - 150 m • Temporal resolution - daily
Boundary Streamflows	• Creator - RMJOC-II Part 2 • Modeling chain – 10 GCMs (32 future streamflows) • Statistically downscaled - bias corrected • Simulations for 2019-2049 • Spatial resolution – 5-6 km • Temporal resolution - daily
GCM – Global Climate Model WRF – Weather Research and Forecasting community mesoscale model DHSVM – Distributed Hydrology, Soils, and Vegetation Model RMJOC-II – River Management Joint Operating Committee (Part 1 - regulated flows)	

SeaTac Temperatures

Temperatures for SeaTac, where weather metrics are representative of City Light's service territory, were developed by the University of Washington (UW) Climate Impacts Group (CIG) and Atmospheric Science Department from new dynamically-downscaled climate projections based on results from the Weather Research and Forecasting community mesoscale model (Skamarock et al., 2005). This dataset provided two key benefits: hourly resolution and dynamical downscaling of the global model into a new Regional Climate Model (RCM). The dynamical downscaling used to generate this dataset shows a distinct improvement from previous statistical downscaling approaches to modeling historical and future weather conditions, as smaller scale topology and dynamics can be resolved. This is a particular advantage in in the Pacific Northwest study area, where weather is significantly impacted by the presence of three mountain ranges and a large area of land-sea interface.

GCM projections were obtained from the Climate Model Intercomparison Project, phase 5 (CMIP5; Taylor et al., 2012). CMIP5 represents a collaborative effort of more than 20 climate modeling groups from around the world, using the same experimental setup, to provide the best available climate modeling. The 12 GCMs included in the WRF ensemble (ACCESS1-0, ACCESS1-3, bcc-csm1-1, CanESM2, CCSM4, CSIRO-Mk3-6-0, FGOALS-g2, GFDL-CM3, GISS-E2-H, MIROC5, MRI-CGCM3, and NorESM1-M) were chosen based on Brewer et al. (2016), who evaluated and ranked GCMs based on their ability to reproduce the past climate of the Pacific Northwest. RCM simulations were dynamically downscaled using the WRF, following the configuration developed in previous work (e.g., Salathé et al., 2010). The GCMs provide the boundary conditions to the WRF simulations. The RCM and its configuration are described in detail in Lorente-Plazas et al. (2018) and Mauger et al. (2018).

Each GCM is typically run for a range of global emissions scenarios, which are essentially storylines of the potential rate and amount of greenhouse gases emitted into the atmosphere over the next century for the entire world. The new ensemble of WRF projections in the RCMs produced by the UW includes one simulation for each of the 12 GCMs based on high-end Representative Concentration Pathways (RCP) 8.5[1] greenhouse gas emissions (GHG) scenario (Van Vuuren et al., 2011). An additional simulation used the moderate RCP 4.5 emissions scenario developed previously for the ACCESS 1.0 GCM. All simulations run from 1970-2099 and are archived at a 1-hour time step and a spatial resolution of 12 km (Mass et al., 2022).

Although the RCM dataset is thought to provide more accurate estimates of extreme events, WRF simulations are known to have general biases relative to observations. Thus, bias correction was carried out using scaling quantile-based bias correction method. The bias and subsequent correction of the bias was performed using observations of hourly temperatures from 1948 to 2021 from the SeaTac NOAA Integrated Surface Database (ISD, station ID: 72793024233). During the analysis for this IRP, bias in the downscaled annual minimum temperatures were discovered and subsequent analysis revealed that this cold bias originated in the original GCMs. Due to their coarse resolution, GCMs do not adequately represent the topography of the region. As a result, they allow cold continental air to flow into Puget Sound, when in reality it would remain confined east of the Cascade and Rocky Mountains. UW performed additional bias correction to address this, but some cold bias remained in the

[1] RCP represent the magnitude of the greenhouse effect corresponding to the amount of energy in watts per square meter (W/m2) that is absorbed across the globe by 2100 given possible future emissions, population growth, technological advance, etc. RCP 4.5 represents a lower-end stabilizing scenario that assumes that emissions mitigating policies are invoked to limit emissions and radiative forcing such that emissions stabilized by mid-century and fall sharply thereafter, while RCP 8.5 represents a higher-end scenario where emissions continue to increase until the end of the 21st century. RCP 8.5 tracks closest to historical emissions.

temperature dataset. Additional detail of the bias correction methods can be found in a technical memo produced by CIG available online[2].

Skagit Hydroelectric Project streamflows

Future streamflow for the Skagit Hydroelectric Project was obtained from a study by the University of Washington, Department of Civil & Environmental Engineering on the hydrology, streamflow temperature, and sediment impacts of climate change on the Skagit River Basin (Bandaragoda et al., 2020). This study utilized data products from *the Integrated Scenarios of the Future Northwest Environment* project[3] (Taylor et al., 2011). For this UW study, a core set of ten GCMs were selected as the best-performing models based on their simulation of 20th century climate in the Pacific Northwest (Rupp et al. 2013). These ten GCMs included: bcc-csm1-1-m, CanESM2, CCSM4, CNRM-CM5, CSIRO-Mk3-6-0, HadGEM2-CC, HadGEM2-ES, IPSL-CM5A-MR, MIROC5, and NorESM1-M. To simulate streamflow, researchers used the Distributed Hydrology Soil Vegetation Model (DHSVM) – a coupled glacio-hydrology model (Clarke et al., 2015; Liang et al., 1994), at 150-m spatial resolution over the Skagit River Basin, with a nested model of 50-m resolution of Thunder Creek subbasin, which has major glacier ice cover at high elevations.

The streamflow modeling steps included: (a) hydrometeorology bias correction to improve model weather input, (b) spin up of the glacier model to develop realistic glacier cover in the glaciated uplands prior to watershed hydrology and streamflow predictions; (c) calibration of DHSVM using select model parameters; (d) model validation using historical streamflow observations; (e) projections of streamflow into the future using CMIP5 model meteorology; and (f) bias-corrections of modeled streamflow to match observations based on monthly mean. Meteorology from the ten GCM models and two GHG emissions scenarios was statistically downscaled using the Multivariate Adaptive Constructed Analog (MACA) method (Abatzoglou and Brown 2012), made available by the Climatology Lab at the University of California Merced[4].

Downscaled meteorology was adapted to better represent the Skagit River Basin weather conditions by using a two-step approach: 1) adjust data to match the spatial distribution from the WRF model), and 2) apply a uniform correction to the WRF output values. The resulting dataset preserves the time series of the GCM output data and includes temperature and

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[2] More detail on the cold-bias correction provided on the UW project website at: https://cig.uw.edu/projects/extreme-weather-and-seattle-city-light-operations/

[3] More detail on the Integrated Scenarios of Future Northwest Environment project can be found here: https://d2k78bk4kdhbpr.cloudfront.net/media/content/files/Integrated_Scenarios_Draft_Final_Report_2014-06-30_V2-1_1.pdf

[4] Learn more about the Climatology Lab at: https://www.climatologylab.org/

precipitation gradients that can be helpful in determining streamflows. Corrected data were disaggregated to 3-hour data using the Mountain Microclimate Simulation Model (MTCLIM) disaggregation routines in the Variable Infiltration Capacity (VIC) hydrology model. VIC climate outputs were then used as inputs for the DHSVM, version 3.1.2. Validation and corrections to the DHSVM were conducted using empirical data on glaciers, naturalized flows at reservoir locations, and observed stream gauges. Future projections were calculated using GCMs from 2010 to 2099.

Boundary Hydroelectric Project streamflows

Future streamflow for the Boundary Hydroelectric Project is available from the River Management Joint Operating Committee (RMJOC). The RMJOC is composed of Bonneville Power Administration (BPA), U.S. Army Corps of Engineers (Corps), and U.S. Bureau of Reclamation (USBR) working collaboratively to continuously evaluate and anticipate vulnerabilities, risk, and resiliency of the Federal Columbia River Power System (FCRPS). The RMJOC released in 2020 its *Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part II: Columbia River Reservoir Regulation and Operations—Modeling and Analyses* (known as RMJOC-II available online at: https://usace.contentdm.oclc.org/digital/collection/p266001coll1/id/9937/rec/6).

To translate projected changes in climate into changes in streamflow, a series of models called an *impact modeling chain* (Chegwidden et al 2019; RMJOC 2018) was used to create large ensembles of possible hydrologic futures. The chain implemented by Chegwidden et al. (2019) and used in Part 2 of the RMJOC-II study analyzes of 160 of these projections consisting of four model decision points:

- Two greenhouse gas scenarios: RCP 4.5 and RCP 8.5
- 10 global climate models (GCM) simulations performing well for the northwest region covering the Columbia River Basin and coastal areas – CanESM2, CCSM4, CNRM-CM5, CSRIO-Mk3-6-0, GFDL-ESM2M, HadGEM2-CC, HadGEM2-ES, Inmcm4, IPSL-CM5A-MR, MIROC5
- Two approaches to temporally and spatially downscale coarse-resolution GCM temperature and precipitation data: bias-corrected spatial disaggregation (BCSD) and MACA
- Two hydrologic model configurations: Prescription Runoff Modeling System (PRMS) and the Variable Infiltration Capacity (VIC) model with three parameterizations (P1, P2, and P3) calibrations

In summary, the RMJOC-II utilized spatially and temporally downscaled input data starting with coarse-scale processes (e.g., global climate models) that were processed to a finer resolution more relevant for impact assessments at the river-basin scale. The global climate model output was downscaled to a finer spatial resolution with statistical downscaling. Hydrological models translated the finer-scale modeled weather patterns to streamflow time series. These hydrology models were calibrated to 7-day flow rates without explicit objectives for extremes or daily scale minima and maxima. City Light obtained daily regulated future flows developed as part of RMJOC-II for Boundary Dam from the Corps.

Climate Model Selection

Due to limitations in available computational capacity, City Light selected a limited number of climate scenarios to evaluate in the IRP framework based on three primary criteria:

- GCMs must cover the Skagit and Boundary hydroelectric projects as well as the greater Seattle area service territory to limit uncertainty introduced by differing GCMs at distinct geographic locations.
- GHG emissions scenarios considered will be high (e.g., RCP 8.5) to represent a future where emissions continue to increase, tracking with historical emissions. Such scenarios are commonly used in local impact assessments in the region, and provide a conservative view of uncertainties in carbon-cycle feedbacks (e.g., land clearing and ice loss) as well as socio-economic influences that lead to a focus on local or regional issues.
- Model simulations should represent a range of future conditions in order to capture impacts from more extreme conditions.

Each GCM simulation represents an equally likely and valid depiction of the future climate. However, climate change projections from GCMs should not be interpreted as forecasts of weather.

Suitability to the Pacific Northwest and Service Area

Different research teams have performed evaluations of the numerous GCMs available to narrow down the models that perform best when validated against the 20th century climate. Rupp et. al. (2013) evaluated 41 GCMs from the CMIP5 suite of model outputs. Their analysis identified the 13 best performing GCMs for the Pacific Northwest through evaluation of nine metrics of spatiotemporal variability in temperature and precipitation. Mote et al., (2015) preformed a follow-up analysis of Rupp et al. (2013) on 20 GCMs and identified a core set of 10 GCMs that performed well overall for the Pacific Northwest based on 18 metrics. These GCMs were selected for use in hydrologic modeling for Skagit River Basin by Bandaragoda et al. (2020). During development of the RMJOCII datasets, two of these top 10 GCMs identified by Mote et al. (2015) were swapped for alternate GCMs due to performance issues and stakeholder engagement. Another analysis of 32 GCMs compared the mean relative error compared to observations of 40 different weather variables, many of which were the same as those evaluated by Rupp et al. (2013), but with a comparatively greater focus on extreme precipitation (Mauger et al. (2018). They also compared the model performances with evaluations of GCMs by other research groups (e.g., Rupp et al, 2013) to show how model selection based on regional performance can vary depending on the metrics evaluated (Brekke et al. 2008).

Examination of the available datasets determined that different GCMs were used in generating future temperature and streamflow projections for City Light areas of interest described above. Table 2 identifies six initially overlapping GCMs for SeaTac and Skagit Hydroelectric Project; only four GCMs overlapped among the temperatures at SeaTac and streamflows at both Skagit and Boundary hydroelectric projects: CanESM2, CCSM4, CSIRO.Mk3.6.0, and MIROC5. Two GCMs initially examined before modeling RA were thought to be the same model (bcc-csm1-1 and bcc_csm1-1-m). However, these are two different model configurations from the Beijing Climate Center modeling group and thus, they were eliminated from consideration in RA modeling.

Table 2 Global Climate Models (GCMs) providing projections at three locations of interest with overlapping models shown in bold

SeaTac	Skagit Hydroelectric Project	Boundary Hydroelectric Project
bcc-csm1-1	bcc-csm1-1-m*	
CanESM2	**CanESM2**	**CanESM2**
CCSM4	**CCSM4**	**CCSM4**
CSIRO-Mk3-6-0	**CSIRO-Mk3-6-0**	**CSRIO-Mk3-6-0**
MIROC5	**MIROC5**	**MIROC5**
NorESM1-M	NorESM1-M	
ACCESS1-0	HadGEM2-CC	HadGEM2-CC
ACCESS1-3	HadGEM2-ES	HadGEM2-ES
FGOALS-g2	IPSL-CM5A-MR	IPSL-CM5A-MR
GFDL-CM3	CNRM-CM5	CNRM-CM5
GISS-E2-H		GFDL-ESM2M
MRI-CGCM3		Inmcm4

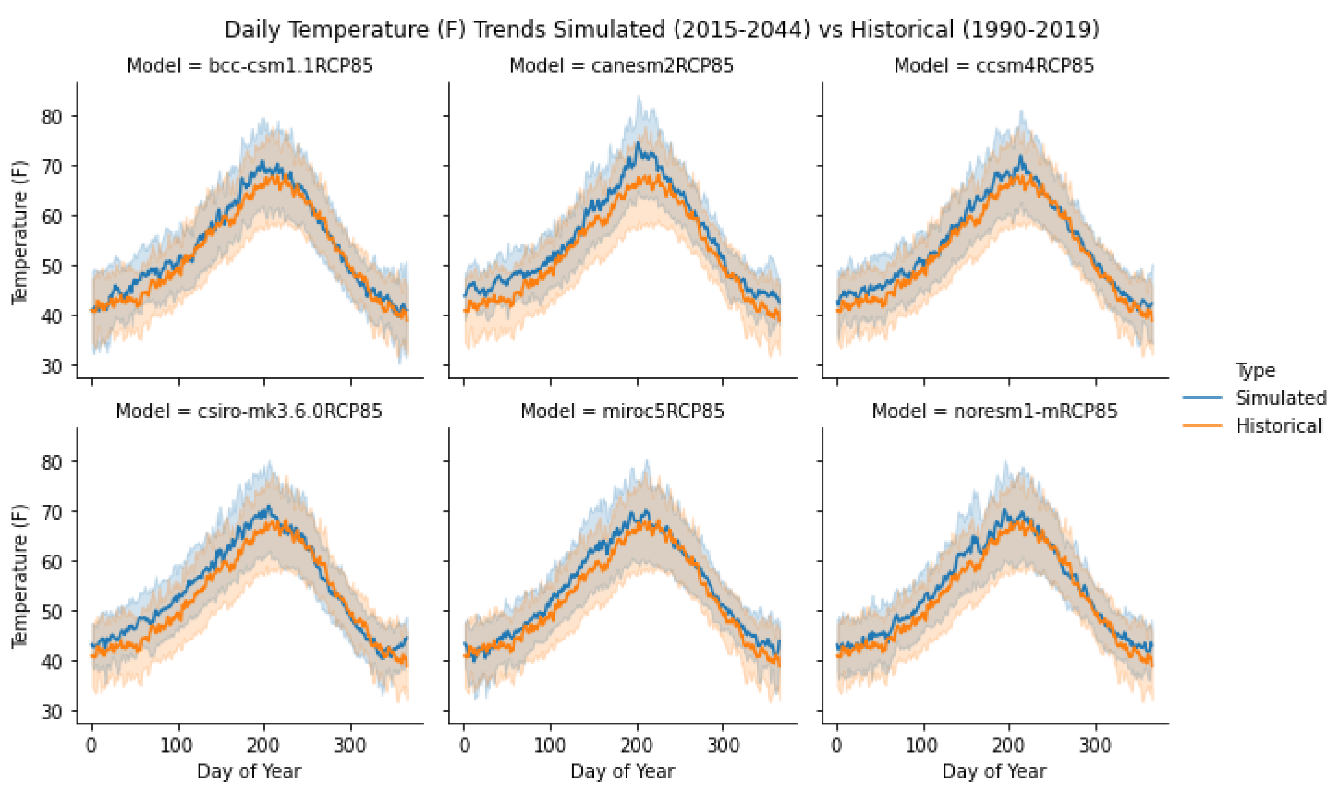
*Originally thought to be the same as bcc-csm1-1; however, this is a moderate resolution (i.e., “m”) of bcc-csm1-1 and thus, are not the same model version.

Suitability for Modeling SeaTac Temperatures

To understand the variability in the future projections (i.e., simulations) of temperatures at SeaTac and help decide which models to focus on in the RA assessment, City Light compared the future projections for the six GCMs shown in bold in Table 2 during the period 1990 through 2019 with observed temperatures from the SeaTac weather station during the same period. For use in the 2022 IRP climate change load scenarios, the GCM output data were analyzed over a 30-year period between 2015 and 2044. Generally, the GCMs showed a warming trend relative to the historical data as depicted in Figure 1. There was significant variability in the strength of the warming signal depending on the individual GCM, the specific simulated weather year, and the season.

Figure 1 below details the daily temperature trends for simulated (2015-2044) and historical (1990-2019) time periods for six global climate models. Shaded areas show standard deviation in daily temperature based on the historical and simulated sample period. The solid line provides the average of simulated and historical data.

Figure 1 Daily Temperature Trends

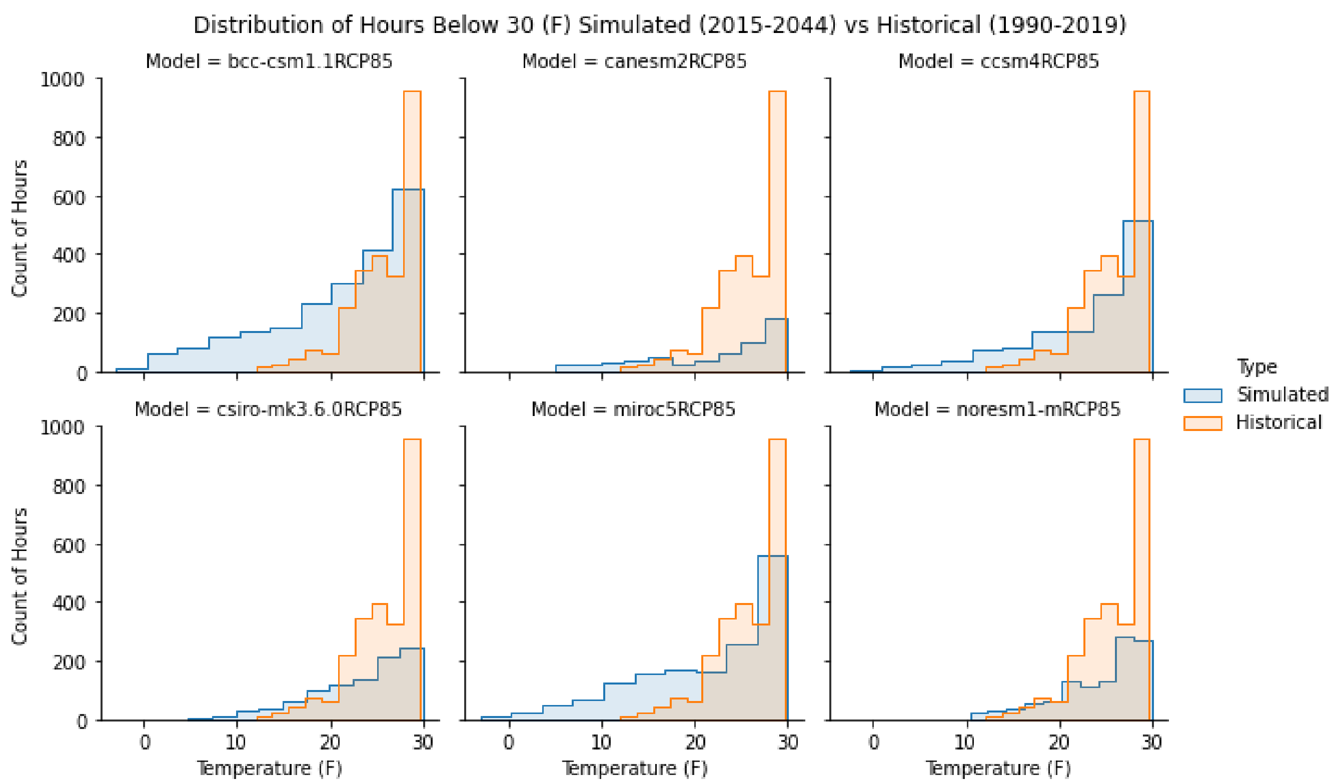


Resource adequacy is heavily impacted by extreme cold events in the winter and heat events in the summer. For both the summer and winter periods the tails of the temperature distributions were compared for each of the six GCMs to the most recent 30-year historical period. Winter tails were analyzed by examining temperature distributions below 30º F, shown in Figure 2 and summer tails were analyzed by examining temperature distributions above 90º F, shown in Figure 3. Hourly temperatures above and below these thresholds generally lead to more pronounced winter and summer peaking conditions, respectively. These tails represent <1% of the overall temperature distribution but have a disproportionate impact on RA.

The six GCMs assessed appear to have fewer occurrences of mild cold events between 20º -30º F compared to the 30-year historical data. The "cold-bias" mentioned above in the Climate Datasets section is more pronounced in certain GCMs, like bcc-csm1-1 and MIROC5, as evidenced by the higher counts of hours below 20º F. All GCMs have hours where temperatures drop below 10º, which is colder than any events in the 30-year historical period.

Figure 2 shows the distribution of hours with average temperature below 30°F for simulated (2015-2044) and historical (1990-2019) time periods for six global climate models.

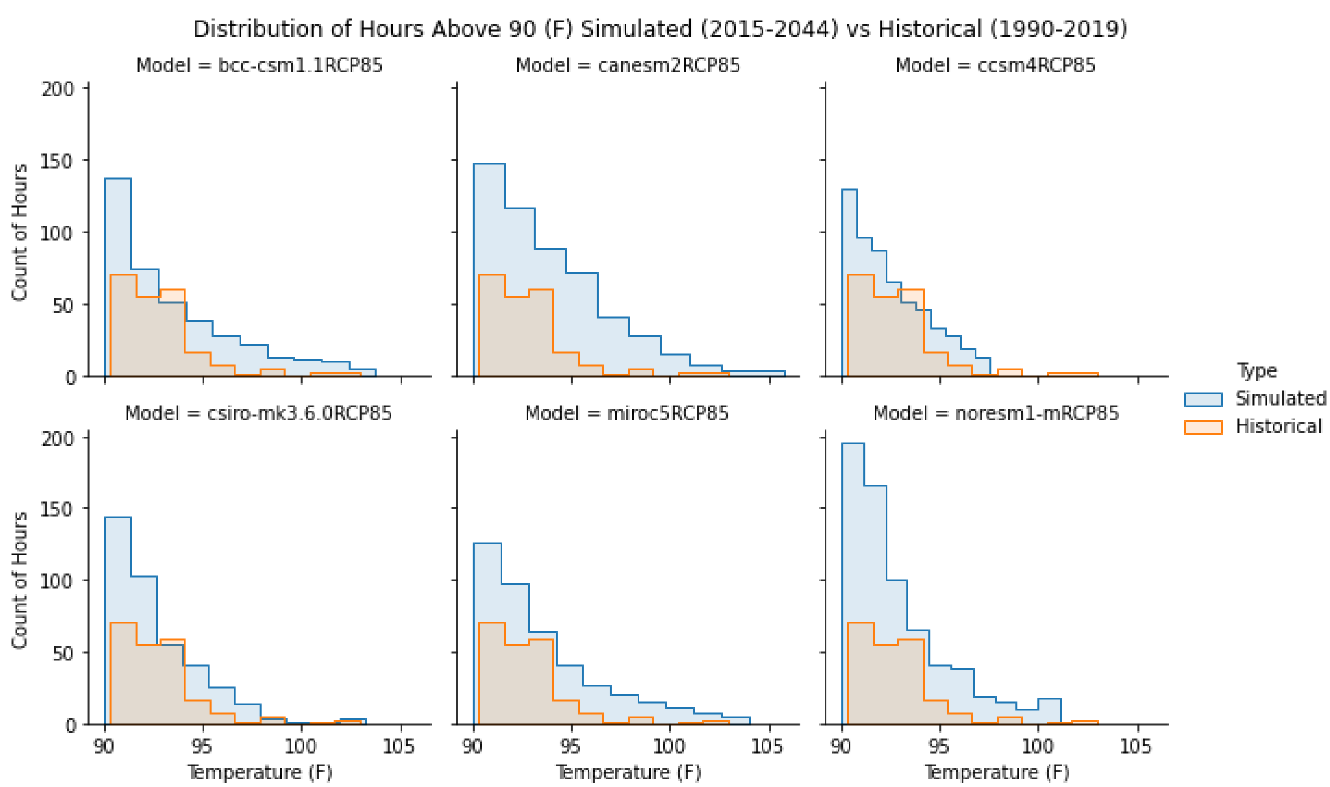
Figure 2 Distribution of Hourly Cold Temperatures



In the summer season all six GCMs have higher counts of hours that exceed 90º F relative to the most recent 30-year history. The CanESM2 model appears to have the strongest warming signal in the summer compared to the other GCMs (Figure 3). City Light also compared GCM extreme heat events with the June 2021 heat event when temperatures at SeaTac reached a record high of 108° F. That heat event was outside of the 30-year historical temperature range used in the 2022 IRP; however, it serves as an important benchmark for potential future summer temperature extremes. None of the candidate GCMs has an event as extreme as the June 2021 heat event, although the CanESM2 model did have an event where temperatures exceeded 105°F.

Figure 3 shows the distribution of hours with temperature above 90°F for simulated (2015-2044) and historical (1990-2019) time periods for six global climate models.

Figure 3 Distribution of Hourly Warm Temperatures



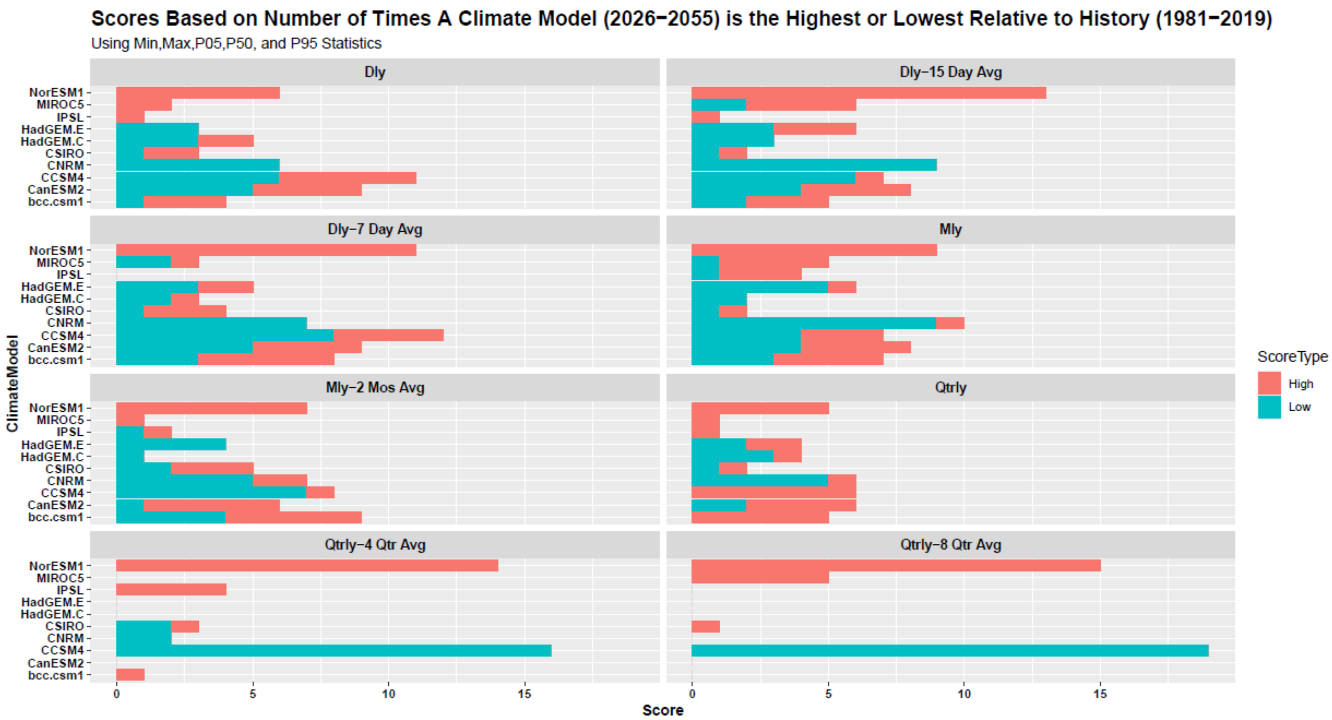
Suitability for Modeling Skagit Hydroelectric Projects Inflows

City Light's analysis of possible future streamflows in the Upper Skagit Basin under climate change used the thirty historical water supply years from 1981 through 2019 as a baseline. These years are considered to represent the current state of the basin. This baseline period was compared directly to modeled water supply resulting from each GCM from 2026 through 2055. This window was chosen to be centered on the 20-year IRP study window, with five additional years on either side of the window to expand the number of feasible water supply years and add additional variability to the model set.

City Light developed a scoring scheme to evaluate the variability in the streamflow generated from the ten GCMs available at the Skagit Hydroelectric Project. The scoring method entailed a count of the number of times a model's resultant streamflow represented the greatest percent deviation (highest or lowest) from the historical distribution each month. Scores were based on statistics using minimum, maximum, 5% percentile, 50% percentile (median), and the 95% percentile for eight different time periods: daily, 7-day rolling average, 15-day rolling average, monthly, 2-month rolling average, quarterly, annual average, and 2-year annual average. Based on this scoring approach, the climate change models that showed the highest scores represented by the total count of high and low percent difference were CCSM4, NorEMS1, CanESM2, and CNRM (Figure 4). While not a criterion, CCSM4 also contained projections similar to the recent flood event in November 2021.

Figure 4 shows the scoring of future hydrology at Skagit Hydroelectric Project for 10 GCMs listed on the left. Bars represent the number of times a GCM future year (2026-2055) distribution represented the greatest difference, either highest (red) or lowest (blue), compared to the historical (1981-2019) distributions. Scores were based on the distributions' minimum, maximum, 5% percentile, 50% percentile (median), and the 95% percentile. The eight panels represent streamflow statistics where scoring was evaluated for eight different time periods: daily, 7-day rolling average, 15-day rolling average, monthly, 2-month rolling average, quarterly, annual average, and 2-year annual average.

Figure 4 Climate Model Scoring Relative to History



Based on their relative scores, the top three models for Skagit are CanESM2, CCSM4 and NorESM1-M. NorESM1-M showed more variation in flows in certain months relative to history compared to other models, but unfortunately the geographic span of this model does not include City Light's Boundary Hydroelectric Project; thus, it was not selected for use in the RA climate change scenario. CanESM2 and CCSM4 both showed higher median flows from February through May, with earlier peak flows, as well as during September and October, compared to the 40-year historical period. CCSM4 is generally wetter in January through March than CanESM2. During June and July, mean annual flows are lower in the future scenarios than historically.

Suitability for Modeling Boundary Hydroelectric Project Inflows

City Light's Boundary Hydroelectric Project is situated on the Pend Oreille River in northeastern Washington State. It is located directly downstream of multiple hydroelectric plants with large storage reservoirs on the Pend Oreille River, specifically Albeni Falls Dam, Hungry Horse Dam, and Sẻliš Ksanka Qḷispẻ Dam. The natural inflows in this portion of the Pend Oreille were taken from the RMJOC-II simulated dataset and were bias corrected to local gages by the UW. Streamflows were then routed by the UW through Corps' reservoir model to derive regulated inflows into the Boundary Hydroelectric Project. Because of the large number (160) of future streamflow projections (GCM-downscaling-hydro), these regulated streamflow projections were filtered based on streamflow metrics to select a few for the RA climate scenarios.

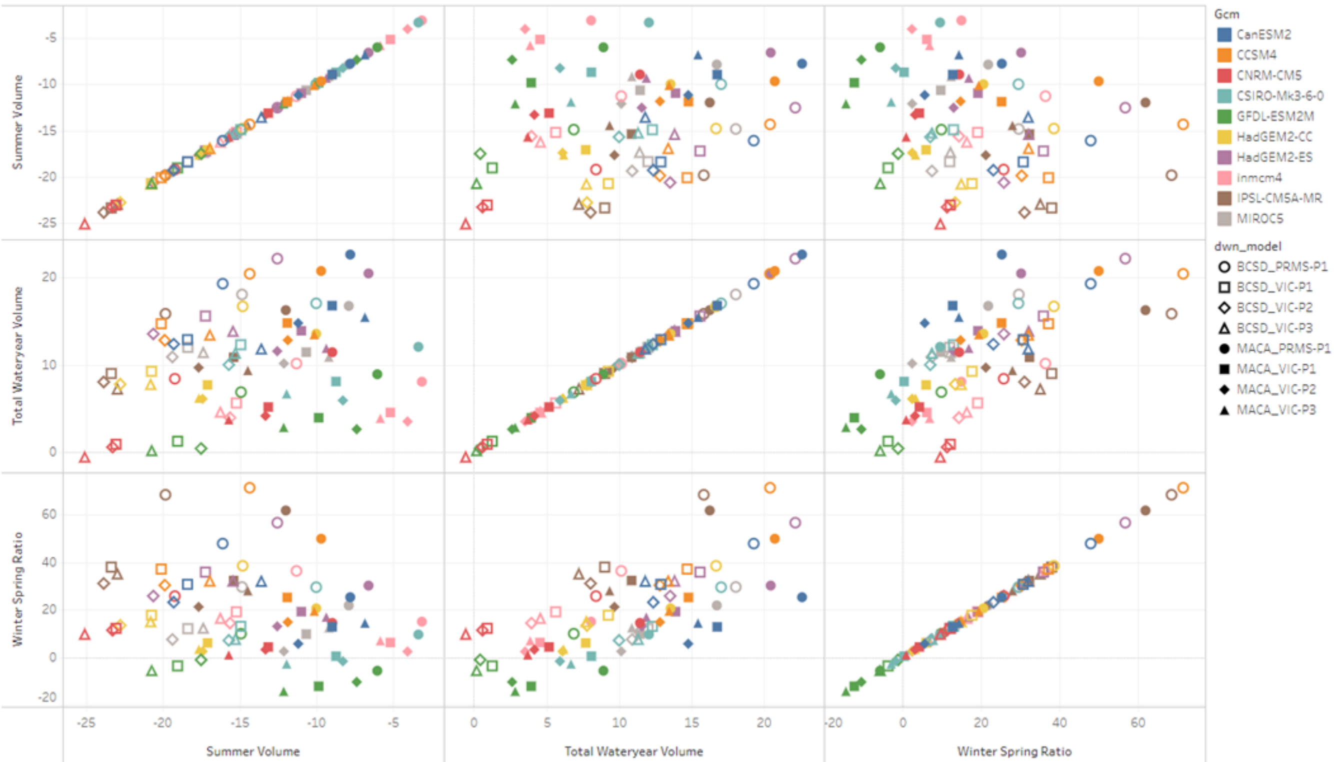
City Light chose to evaluate which GCM streamflow output to use in the 2022 IRP analysis based on three streamflow metrics of interest that were felt to represent the most important characteristics for water management at Boundary Dam: summer volume (Jun.-Aug.), total water year volume (Oct.-Sept.), and winter (Dec-Mar)-spring (Apr-Jul) volume ratio. The winter-spring volume ratio metric is particularly useful for showing the change in volume timing associated with warmer temperatures and less snowpack. Thus, it can reveal a temperature-driven shift in streamflow timing even when the total precipitation remains constant. A high ratio value means more winter precipitation is coming as rain and less spring snowmelt. Summer volumes are important to capture drought risk, while annual volumes indicate available annual water supply. The parameter space for these metrics across all GCMs is shown in Figure 5.

As part of the RMJOC-II studies, the Corps developed a tool to capture low, medium, and high scenarios for streamflow metrics of interest as decided by the tool's user. The tool uses a greedy algorithm to capture the smallest number of future projections that represent the widest range of each streamflow metric. This range is represented by projections that capture values near the 10th, 50th, and 90th percentile for each metric of interest.

The CIG applied this tool on naturalized monthly flows at Boundary Dam, which were readily available at the time the tool was applied. Daily regulated flows were later acquired to assess RA under climate change scenarios. The tool was run for only the high GHG emissions (RCP 8.5) scenarios of the four GCMs that overlapped with SeaTac and Skagit project locations in order to reduce the number of future streamflow projections to 32 model simulations when applying the tool.

Figure 5 highlights a matrix of scatter plots showing model space for various GCMs in different colors and various downscaling methods with two hydrology models (VIC and PRMS) and parametrizations (model_Px) indicated by shapes. Parameter space is shown for future (2020-2049) percent change from historical (1976-2005) for three streamflow metrics: summer volume, total water year volume, and winter-to-spring volume ratio. The figure was created by Jason Won of University of Washington Climate Impacts Group.

Figure 5 GCMs and Downscaling Methods



The streamflow simulations resulting from the following models were selected by the Corps' tool as the best representatives of the 10th, 50th, and 90th percentiles in model simulations for annual volume, summer volume and winter-spring (liquid runoff) volume ratio:

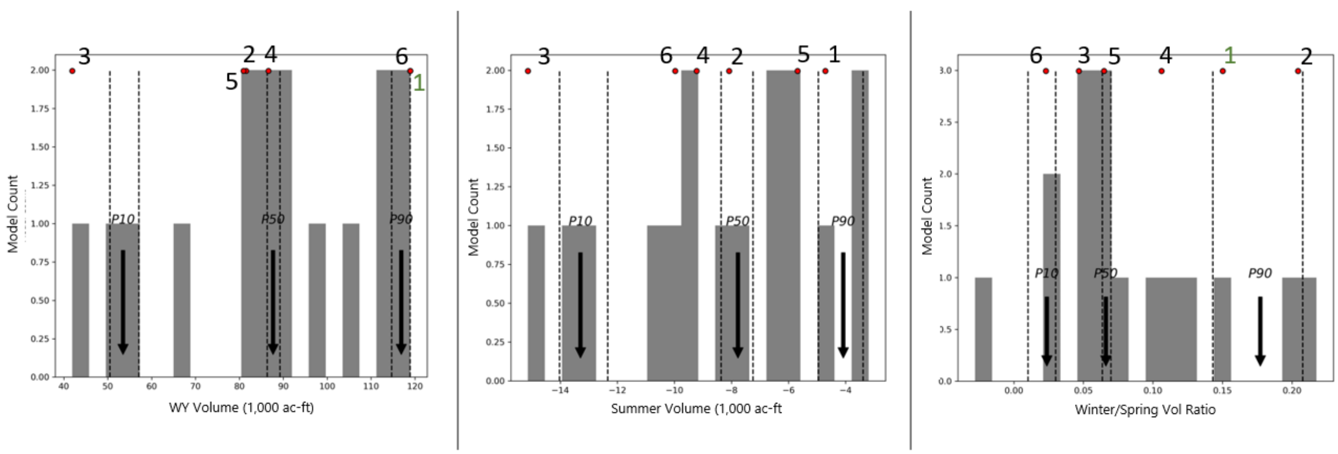
- CCSM4_RCP85_MACA_PRMS_P1
- CanESM2_RCP85_BCSD_PRMS_P1
- MIROC5_RCP85_BCSD_VIC_P1
- MIROC5_RCP85_BCSD_PRMS_P1
- MIROC5_RCP85_MACA_PRMS_P1
- CSIRO-Mk3-6-0_RCP85_BCSD_VIC_P1

The distributions of the models for different streamflow metrics are shown in Figure 6. Note these plots show the change in each metric from historical simulations for each model. The total count of simulations represents 16 derived from the four overlapping GCMs with Skagit and SeaTac and four different downscaling and hydrology model parameterizations created for each GCM.

In the context of streamflow output from all the GCMs considered in this study, the CanESM2 is representative of the median change in annual water volume and summer flows but produces a relatively high change in winter-spring volume ratio (indicating more winter precipitation as rain vs snow). CCSM4 also produces a relatively high change in winter-spring volume ratio and has the largest and smallest change in annual and summer volume, respectively. CSIRO-Mk3-6-0 also has a relatively high change in annual volume with a low change in summer flow, and a low change in winter-spring ratios (i.e., less of a shift in streamflow timing). The MIROC5 GCM future streamflow future changes depend on the downscaling method and hydrology model. MIROC5 with BCSC downscaling and the VIC hydrology model shows the lowest change in annual volume, but the greatest change in summer streamflow volume, with a relatively low change in winter-spring volume ratio. MIROC5 with BCSC downscaling and PRMS hydrology model had a near median change in all three metrics. MIROC5 with the MACA downscaling and PRMS hydrology had a below median change in annual volume but an above median change in summer volume, with a median change in winter-spring volume ratio.

Figure 6 shows the distribution of models simulating future streamflow projections from RMJOC-II study representing the change between the 2030s (2020-2049) and historical (1976-2005) simulations for water year (Oct-Sept) volume, summer volume, and winter-to-spring volume ratio. Regions that represent the 10th, 50th, and 90th percentile for each streamflow metric are show within dashed lines. Labels for six models are shown next to red dots for the models selected by the U.S. Corps of Engineer's tool. The figure was created by Jason Won of University of Washington Climate Impacts Group.

Figure 6 GCM simulated future streamflow projections



1. CCSM4_RCP85_MACA_PRMS_P1
2. CanESM2_RCP85_BCSD_PRMS_P1
3. MIROC5_RCP85_BCSD_VIC_P1
4. MIROC5_RCP85_BCSD_PRMS_P1
5. MIROC5_RCP85_MACA_PRMS_P1
6. CSIRO-Mk3-6-0_RCP85_BCSD_VIC_P1

Final model selection targeted two GCMs for conducting climate change scenarios for RA. The two selected GCMs were CanESM2 and CCSM4 because these represented a broad range of future conditions of the temperatures in the Seattle service territory and streamflow at City Light's two primary hydroelectric projects. Additionally, these models showed less temperature cold bias than others. The MIROC5 and CCIRO models did not represent extremes well at Skagit Hydroelectric Project and only for some extremes at the Boundary Hydroelectric Project. CanESM2 is the Canadian Centre for Climate Modeling and Analysis with an atmospheric resolution of 2.8x2.8 longitude and latitude. CCSM4 is the National Center for Atmospheric Research, USA with a resolution of 1.25x0.94 longitude and latitude. The model comparison analysis performed by Rupp et al. (2013) identified these two models among the best performers in the Pacific Northwest. Furthermore, these two models also coincide with the GCMs selected by Northwest Power and Conservation Council in the 2021 Northwest Power Plan.

Climate Model Analysis

To create a 20-year sampling window to represent the 2030 and 2040 forecast years for the 2020 IRP climate change scenarios, the temperature and streamflow (hydro) data were sampled from 10 years before and after to represent the variability surrounding the forecast years. For example, forecast year 2030 would use simulated temperatures and hydro from forecast years 2021 – 2040. This is primarily because Boundary Hydroelectric Project simulated streamflow data starts in Oct. 2019 and ends in Sept. 2049 (water years 2020-2049), limiting the sampling window for a 2040 forecast. Longer windows (e.g., +/- 15 years) were examined and found to produce results similar to the 20-year window in pattern; thus, it was determined that the 20-year sampling window around the forecast year did not have appreciable effect on the results. In contrast, the 2022 IRP Baseline forecast relies on 30-year historical temperatures from 1991-2019 and 39 years of historical hydro conditions from 1981-2019.

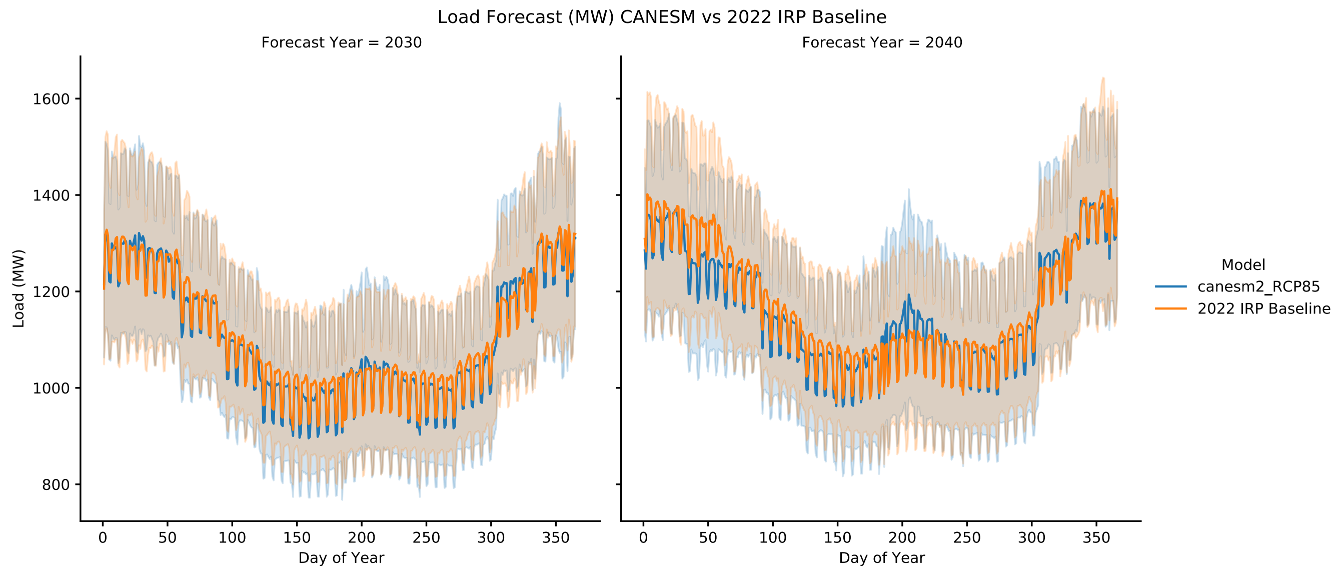
Future Temperature effects on Load: CanESM2

On an annual energy basis, loads under the CanESM2 scenario are 0.8% and 1.0% below the 2022 IRP Baseline forecast in forecast years 2030 and 2040, respectively.

The seasonal load profile of the CanESM2 and 2022 IRP Baseline load forecasts are compared in Figure 7 below. Confidence bands are created based on the standard deviation of hourly loads on a given day in the forecast year. The CanESM2 and 2022 IRP Baseline loads have a similar distribution in forecast year 2030. CanESM2 has lower expected loads in the shoulder seasons, and slightly higher expected loads in the summer. In 2040 the CanESM2 forecast has more pronounced summer loads consistent with the stronger summer warming trend exhibited in this GCM.

Figure 7 shows the simulated daily load profile in 2030 and 2040. The solid orange line represents the average daily load profile for the 2022 IRP Baseline forecast while the solid blue line represents the average based on the CanESM2 model. The shaded areas represent the standard deviation of daily load values on a given day based on the distribution of underlying load data under different weather conditions.

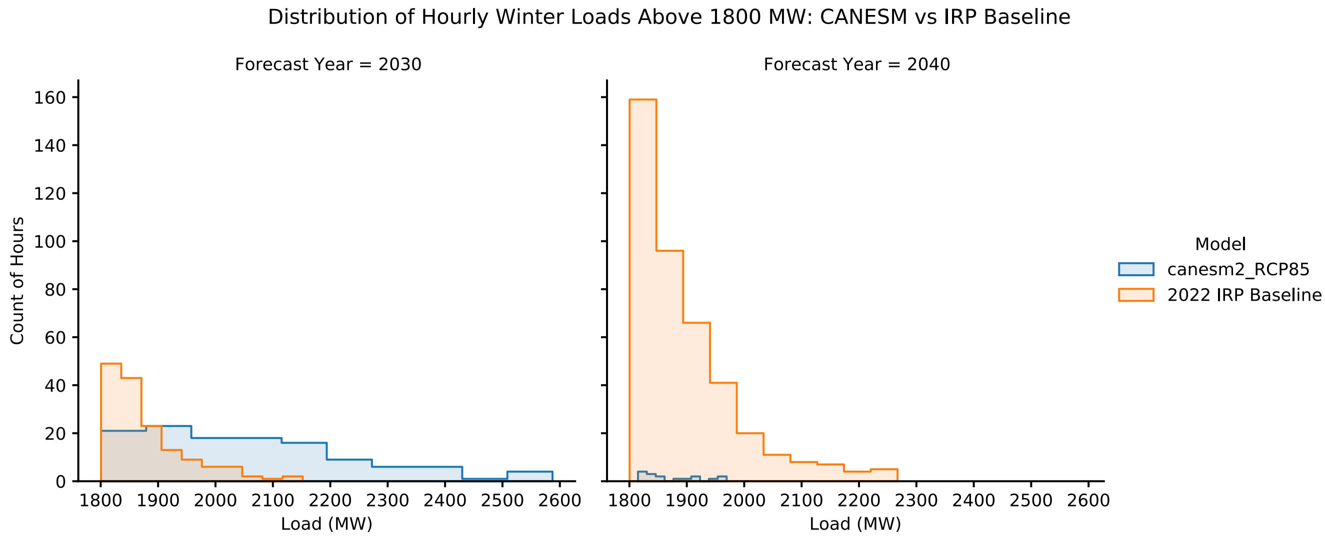
Figure 7 Simulated City Light Load Profile in 2030 and 2040 for CanESM2



Resource adequacy in the winter is more heavily driven by extreme cold temperatures that lead to high load events. An extreme winter load event was defined as any hour in when gross load exceeds 1800 MW. The distribution of extreme winter load events for the 2022 IRP Baseline and CanESM2 scenario is shown in Figure 8 below. In forecast year 2030, the CanESM2 model has higher counts of extreme winter load events that exceed 2000 MW, compared to the 2022 IRP Baseline; this is primarily driven by the "cold-bias" discussed above that is an artifact of the coarse spatial granularity of GCMs. By 2040 the CanESM2 model shows a much stronger warming signal compared to the 2022 IRP Baseline and commensurate reduction in extreme winter load events, compared to the 2022 IRP Baseline load forecast.

Figure 8 shows the distribution of hourly winter load above 1800 MW in 2030 and 2040. The shaded orange and blue areas represent the distributions for the 2022 IRP Baseline and CanESM2 scenarios respectively.

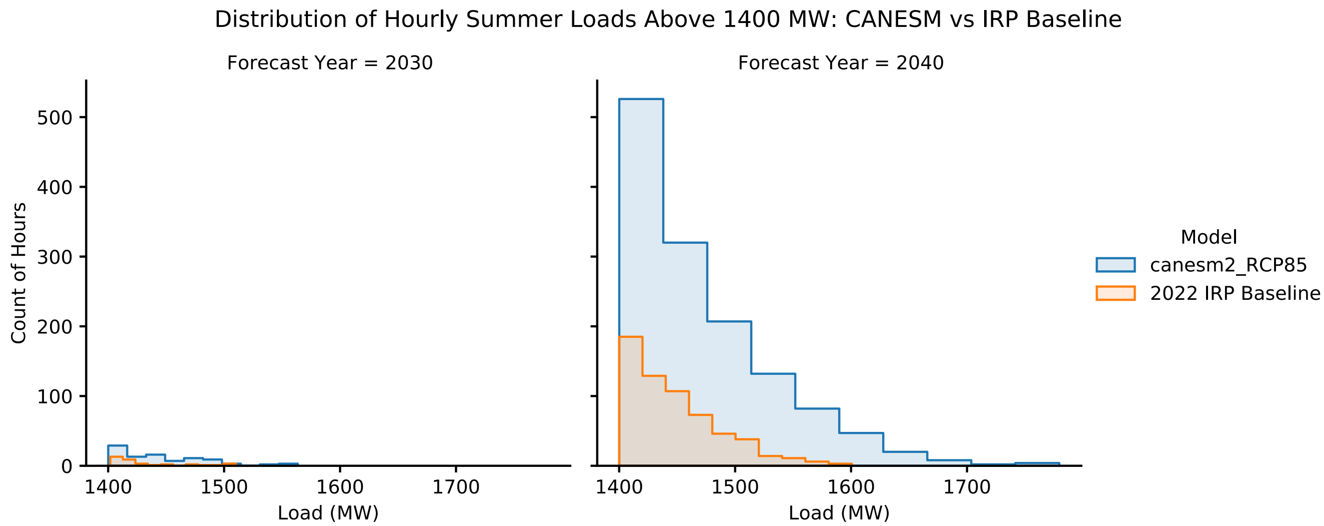
Figure 8 Distribution of Hourly Winter Loads Above 1800 MW CanESM2



Resource adequacy in the summer is heavily impacted by typically low water supply conditions and extreme heat events. The distribution of extreme summer load events for the 2022 IRP Baseline and CanESM2 scenario is shown in Figure 9 below. Both the 2022 IRP Baseline and CanESM2 scenarios point to growing summer loads because of base-load growth and increased saturation of air conditioning. The stronger warming signal in the CanESM2 model indicates a more frequent occurrence of summer extreme load conditions and higher absolute peaks that exceed 1600 MW. For reference, City Light set a new summer peak of 1,534 MW during the June 2021 heat event.

Figure 9 shows the distribution of hourly summer load above 1400 MW in 2030 and 2040. The shaded orange and blue areas represent the distributions for the 2022 IRP Baseline and CanESM2 scenarios respectively.

Figure 9 Distribution of Hourly Summer Loads Above 1400 MW CanESM2

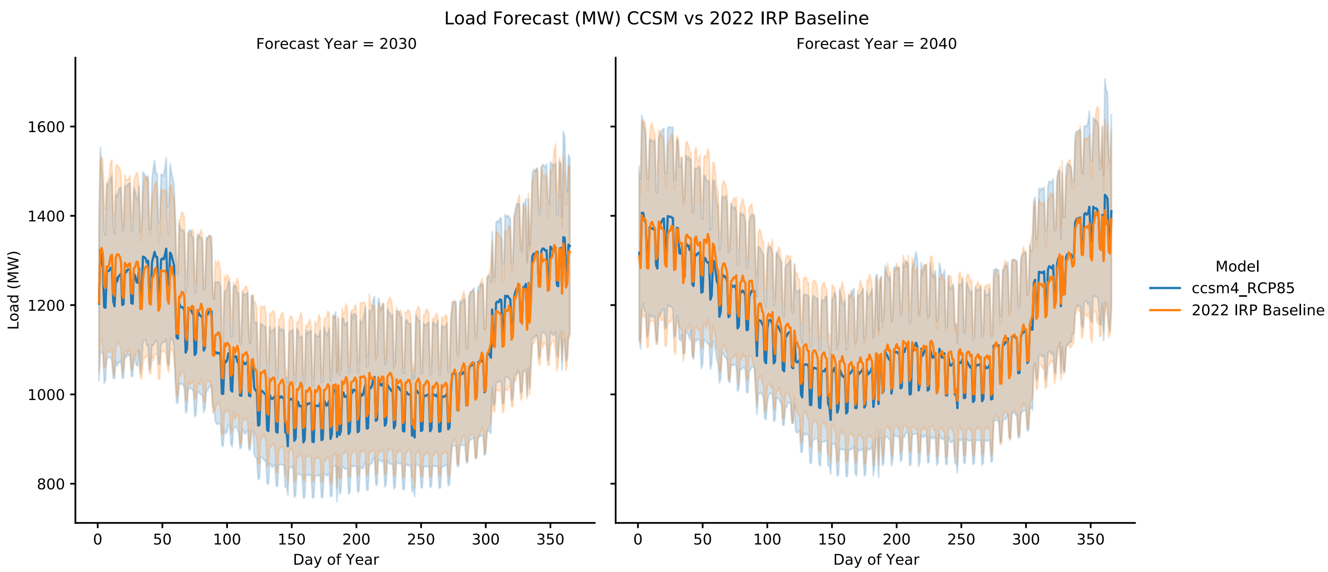


Future Temperature effects on Load: CCSM4

The seasonal load profile of the CCSM4 and 2022 IRP Baseline load forecasts are compared in Figure 10 below. On an annual energy basis, the CCSM4 scenario has 1.1% and 0.8% lower loads in 2030 and 2040 respectively. The seasonal load profile of the CCSM4 scenario is similar to the 2022 IRP Baseline profile; loads in the shoulder season in the CCSM4 scenario are lower than the 2022 IRP Baseline. Compared to CanESM2, the CCSM4 model has a less pronounced warming signal in the winter and summer seasons (Figure 7 and Figure 10).

Figure 10 shows simulated daily load profile in 2030 and 2040. The solid orange line represents the average daily load profile for the 2022 IRP Baseline forecast while the solid blue line represents the average based on the CCSM4 model. The shaded areas represent the standard deviation of daily load values on a given day based on the distribution of underlying load data under different weather conditions.

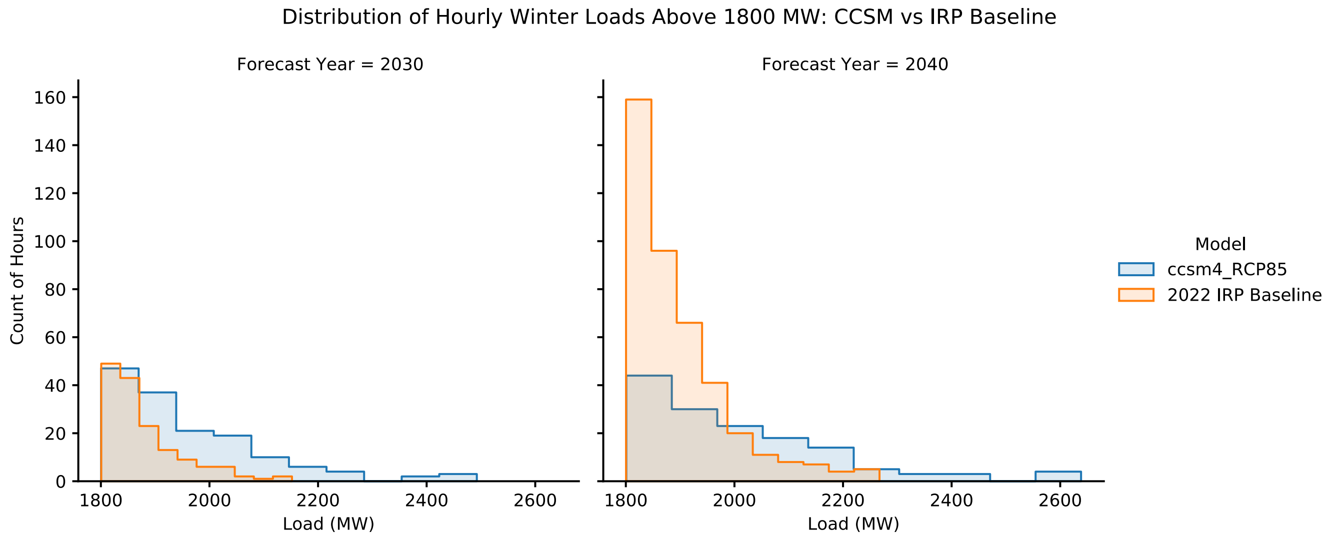
Figure 10 Simulated City Light Load Profile in 2030 and 2040 for CCSM4



Winter extreme load values, hourly load exceeding 1,800 MW, for the CCSM4 scenario and 2022 IRP Baseline load forecasts are shown in Figure 11 below. In forecast year 2030, the CCSM4 scenario has higher occurrences of extreme winter load events compared to the 2022 IRP Baseline load forecast. The "cold-bias" in the CCSM4 model also drives more frequent occurrence of extreme load values in excess of 2,000 MW relative to the 2022 IRP Baseline forecast. By 2040 the CCSM4 scenario has fewer occurrences of extreme winter load events because of the gradual warming trend in the model. The "cold-bias" in the CCSM4 model is still present in forecast year 2040 and creates a longer-tail relative to the 2022 IRP Baseline forecast with the most extreme hourly load values exceeding 2,200 MW.

Figure 11 shows the distribution of hourly winter load above 1800 MW in 2030 and 2040. The shaded orange and blue areas represent the distributions for the 2022 IRP Baseline and CCSM4 scenarios respectively.

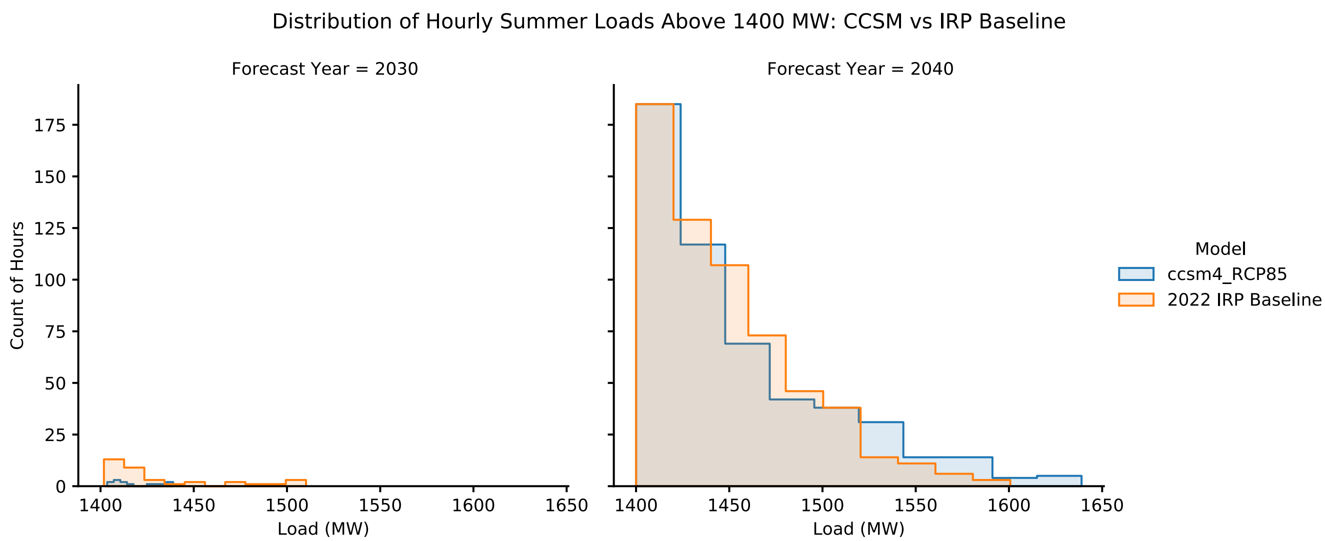
Figure 11 Distribution of Hourly Winter Loads Above 1800 CCSM4



Summer extreme load values, hourly load exceeding 1,400 MW, for the CCSM4 scenario and 2022 IRP Baseline load forecasts are shown in Figure 12 below. In forecast year 2030, the 2022 IRP Baseline both have low occurrences of extreme summer load events. By forecast year 2040 the number of extreme load events in both the CCSM4 and 2022 IRP Baseline forecasts increase significantly due to base-load growth and increased saturation of air conditioning. The warming trend in the CCSM4 scenario leads to a longer tail compared to the 2022 IRP Baseline forecast with extreme load values that exceed 1,600 MW.

Figure 12 shows the distribution of hourly summer load above 1400 MW in 2030 and 2040. The shaded orange and blue areas represent the distributions for the 2022 IRP Baseline and CCSM4 scenarios respectively.

Figure 12 Distribution of Hourly Summer Loads Above 1400 MW CCSM4



Future climate change regulated flow impacts

A large portion (~50%) of City Light's generation comes from the Skagit and Boundary hydroelectric projects, two of the largest owned resources by City Light. As part of assessing the climate change scenarios, regulated streamflow data for each of these projects was either obtained or created. The RMJOC study provided hourly regulated streamflow projections for Boundary Hydroelectric Project. Future stream inflow projections to the Skagit Hydroelectric Project reservoirs were produced by the UW CIG by inputting GCM meteorology into DHSVM and bias-correcting the result, as described above. The resulting inflow data were then processed through SCL's internal operations planning model to derive discharge from each of the three Skagit project dams; however, only Ross Dam will be analyzed in this appendix. The operations planning model ensures the resulting regulated discharge complies with SCL's current operating requirements around flood risk mitigation, fish protection, and summer recreation.

For the 2022 IRP Baseline, 39 years of historical streamflow from 1981 to 2019 are used for both Boundary (Figure 13) and Ross (Figure 14) regulated discharge. For the climate change scenario with CanESM2, the regulated streamflow at Boundary Dam shows higher discharge between December and late May compared to the 2022 IRP Baseline. Additionally, the peak discharge occurs about one month earlier. The variability in discharge also increases during this period. Conversely, summer (June through August) predicts less discharge from Boundary than in the past. There is another rise in discharge during October through early November under the CanESM2 projection compared to historical average, likely the result of more intense autumn precipitation. There is relatively little difference between 2030 and 2040 forecast years

(Figure 13). For Ross Dam, regulated discharge under CanESM2 is slightly higher in the first half of the year (January through June) and less in the second half of the year (July through December) compared to historical. Variability is higher in the spring but relatively similar in other seasons. These patterns are similar for 2030 or 2040 forecast years.

Figure 13 shows the Boundary Dam mean regulate discharge and standard deviation for both 2022 IRP Baseline using years (1981-2019) and CanESM2 climate change model using 2020-2039 and 2030-2049 for forecast years 2030 and 2040, respectively.

Figure 13 Boundary Dam Discharge Forecasts CanESM2

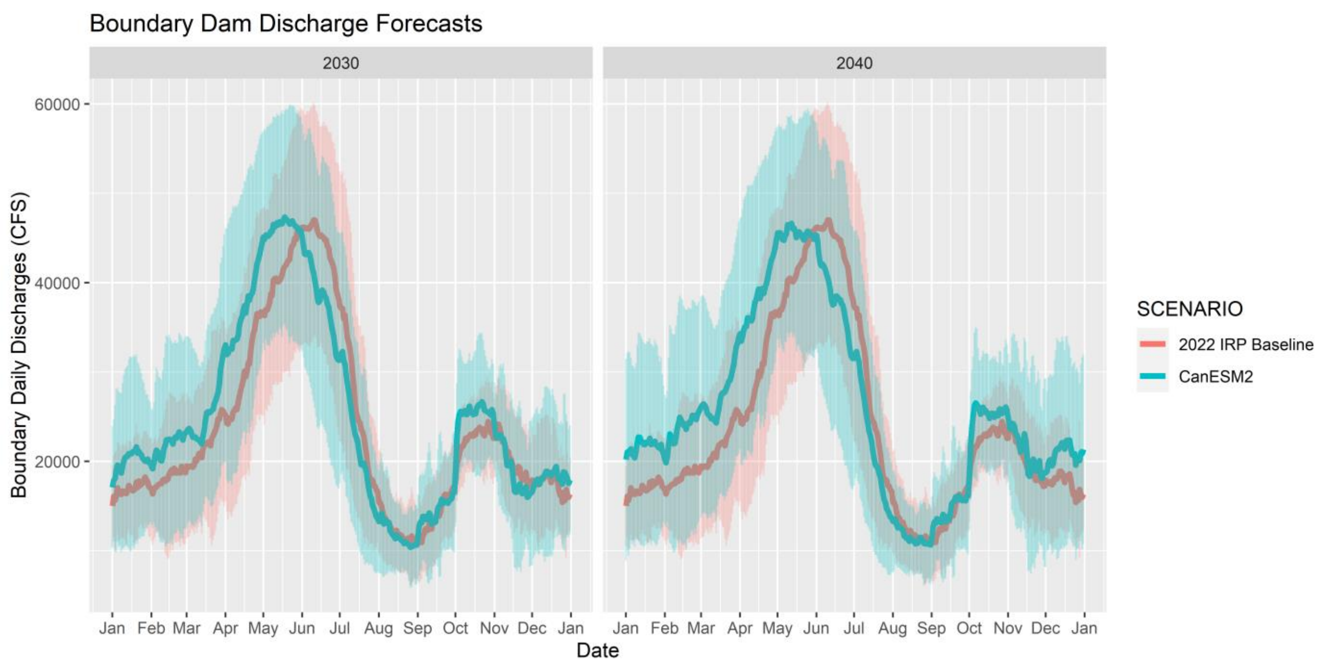
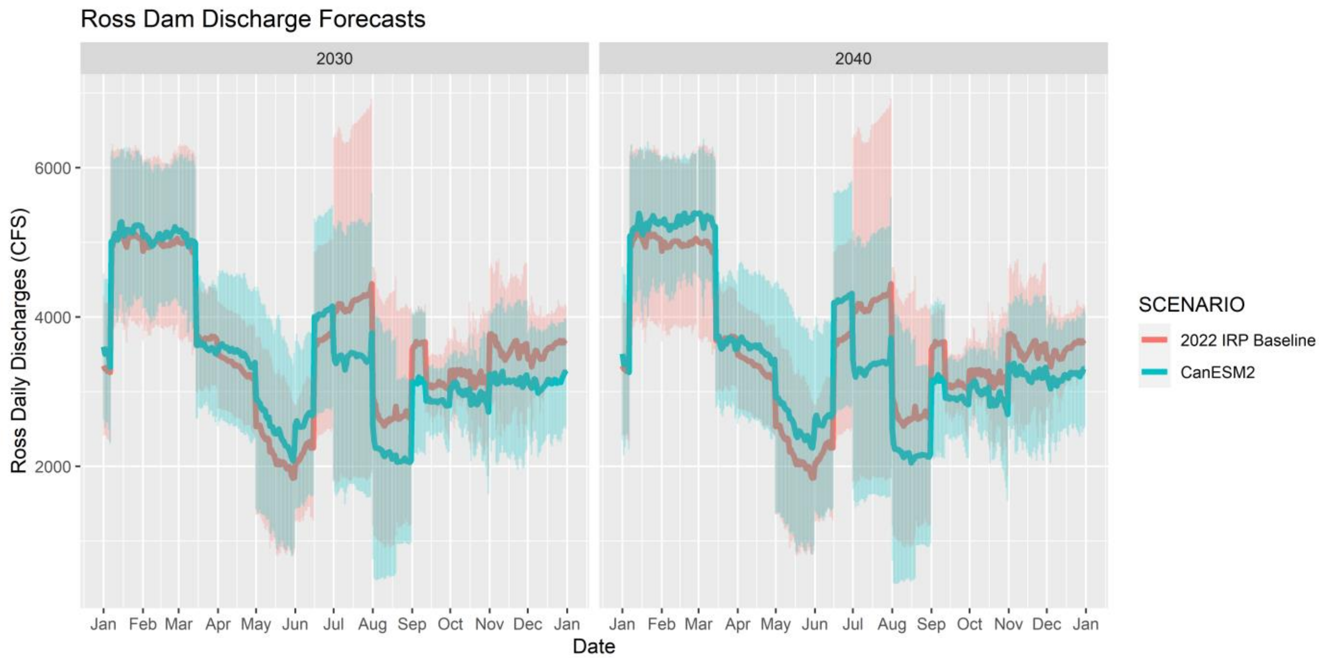


Figure 14 shows the same data as in Figure 13 except for Ross Dam.

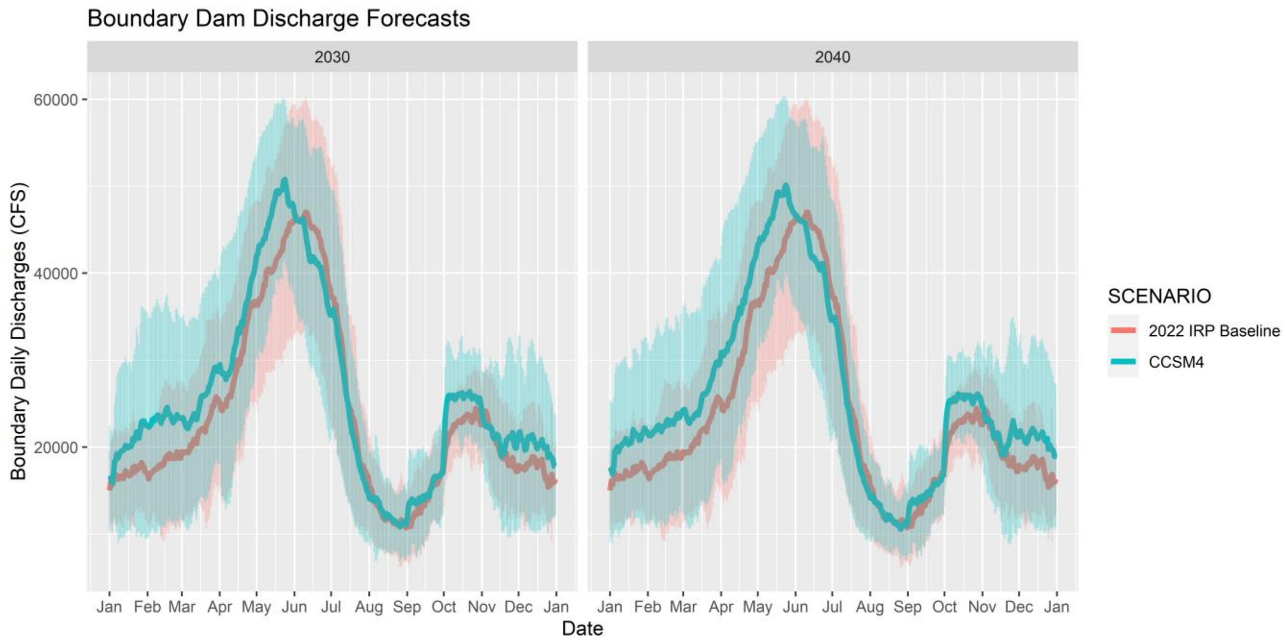
Figure 14 Ross Dam Discharge Forecasts CanESM2



Comparisons of regulated discharge under 2022 IRP Baseline and the CCSM4 climate change model at Boundary and Skagit projects are shown in Figure 15 and Figure 16, respectively. Patterns at Boundary Dam seen under CCSM4 are similar to those described above under CanESM2, except that the average peak is higher under CCSM4 than historical; mean peak discharge was similar under CanESM2 and historical. There is also little difference in mean discharge in late summer but greater difference in December between the CCSM4 climate change scenario and 2022 IRP Baseline, than for CanESM2.

Figure 15 shows the same data as Figure 13 except for CCSM4 climate change model.

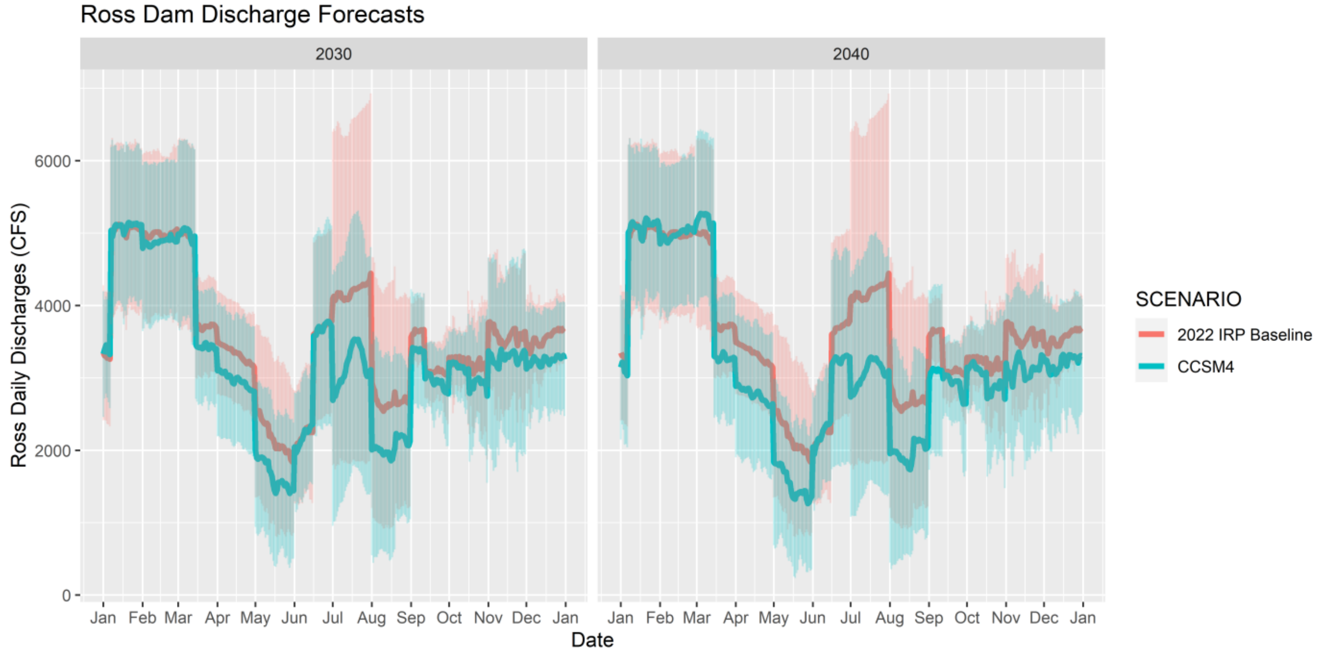
Figure 15 Boundary Dam Discharge Forecasts CCSM4



When examining Ross Dam, future projected discharge under CCSM4 is lower than historical between April and June for both 2030 and 2040 forecast years (Figure 16), which is opposite from discharges under CanESM2 (Figure 14). Other months are similar in patterns under both climate change scenarios.

Figure 16 shows the same data as Figure 14 except for CCSM4 climate change model.

Figure 16 Ross Dam Discharge Forecasts CCSM4



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APPENDIX 8: RESOURCE ADEQUACY

Executive Summary

Through the 2022 Integrated Resource Plan (IRP) and detailed in Appendix 5: Create Top Portfolio, City Light has chosen a top portfolio (P11: Balanced) which meets resource adequacy needs using the 2022 IRP Baseline load forecast. In order to evaluate how well this top portfolio and other competing portfolios may meet future needs, they were evaluated under a series of climate change and electrification scenarios. In addition, P11 was evaluated for risk of resource inadequacy by using a stress-test scenario that reduces the energy contribution of various resources. The goal of this appendix is to present the top seven 2022 IRP portfolios built under the 2022 IRP Baseline, and then examine how these portfolios perform under these additional scenarios with respect to resource adequacy metrics.

Key findings from these scenarios and stress tests include the following:

- Key Finding #1 – Under the climate change scenarios, none of the top seven 2022 IRP portfolios adequately meet City Light's resource adequacy metric. Results show that the largest deficits occur in the summer (July/August). This finding highlights the importance of establishing additional resource adequacy metrics in future resource planning efforts.
- Key Finding #2 – Under the Electrification Rapid Market Advancement (RMA) scenario, none of the top seven 2022 IRP portfolios adequately meet City Light's resource adequacy metric. Electrification results in higher and more variable winter loads than scenarios including no additional electrification; this suggests City Light should look to acquire resources that have more winter flexibility, especially in December, and should also plan for future transmission availability and demand-side resource options.
- Key Finding #3 – The top portfolio, P11, relies on supply-side and demand-side resources, particularly in the summer, in order to reliably meet load. If the top portfolio's supply-side solar, supply-side wind, or demand-side energy efficiency resources are reduced by more than 20%, City Light's resource adequacy metrics would not be met in the summer of 2040.

Introduction

This appendix contains information about the optimization model used to evaluate City Light resource adequacy; details on the two climate change scenarios, an electrification scenario, and the stress tests placed on the 2022 IRP top portfolio; and the results of the resource adequacy analysis on these scenarios.

Modeling Resource Adequacy

The Hydro Risk and Reliability Analyzer (HYDRRA) tool is a Monte Carlo simulation optimization model that is used in the IRP for resource adequacy (RA) assessments.

For the 2022 IRP Baseline and Electrification RMA RA analyses, HYDRRA uses combinations of historical years' water supply and temperature to assess the reliability of City Light's portfolio of energy resources under their respective scenarios. Water supply years are drawn from the historical record between 1981 and 2019 inclusive, and temperature years are drawn from the historical record between 1990 and 2019 inclusive. HYDRRA optimizes hydroelectric dam operations (the largest source of variability in City Light's portfolio) for each permutation of water supply and temperature with respect to the load forecast for each year of the study periods. HYDRRA then calculates the resulting portfolio reliability metrics. For example, the 1981 historical water supply year combined with 1990 historical temperature year using the 2022 Baseline load forecast contributes one simulation to the ensemble or collection of model simulations. Thus, a total of 1,170 different simulations were run for both the 2022 IRP Baseline and for the Electrification RMA scenario.

The electrification scenario was developed in partnership with the Electric Power Research Institute (EPRI). Three electrification load scenarios were developed: a moderate market advancement scenario, a rapid market advancement scenario, and a full electrification by 2030 scenario. For the 2022 IRP, the middle scenario called "Rapid Market Advancement" was chosen, which follows the City of Seattle's climate action plan to achieve zero net greenhouse gas emissions by 2050.

For climate change RA analysis, each Global Climate Model (GCM) has simulated water supply years and temperature years for use in the RA analysis. For each GCM, 400 simulations were run using HYDRRA based on 20 temperature years and 20 water supply years. The climate change scenarios are based on the meteorology from GCMs CanESM2 and CCSM4, where both the distribution of temperatures and hydrology are simulated to account for climate change in years 2030 and 2040.

Lastly, the 2022 IRP top portfolio was stress tested under several sensitivity risks where the hourly output of a resource, or the amount of energy from that resource available to City Light's customers, was reduced by 20%.

HYDRRA Background, Inputs, and Assumptions

The HYDRRA setup uses all current City Light non-variable resources and power contracts to serve load. The decision variables in each of the simulations are the Ross, Diablo, and Boundary hydro dam units, where there is flexibility in generation to meet load. HYDRRA includes planned and unplanned outages for these hydro dam units future forecast years. For the planned outage schedules in the next 5 years, HYDRAA uses the schedule developed by City Light's outage coordination planning. For years outside this planning window, historical planned outage data is used to sample planned outage schedules. For unplanned outages, HYDRAA samples historical unplanned outages for each future forecast year. HYDDRA uses an assumed market reliance of 200 MW for each hour of each year in the study period. This assumption is based on an evaluation of historical market reliance by City Light. Through interviews with Power Marketing Operations and former System Operations Center staff, it is also assumed that City Light's Boundary Hydroelectric Project can provide additional operational flexibility. This additional flexibility is applied once the HYDRRA simulation is completed, and it reduces deficit events that are four hours or less by up to 200MW each hour. Post-simulation adjustment to events is limited to only weekday events for all months except July and August; operational flexibility in the summer is more constrained due to recreational activities that limit the lake level operating range. Additionally, City Light's day-ahead power scheduling for the weekend can be more limited. City Light's RA metric is only counted for events beyond this level of market reliance and hydro flexibility, where the portfolio is not able to meet load demands.

HYDRRA Output Metrics

Each simulation of HYDRRA is completed for all hours of a specific forecast year. For the times that the City Light portfolio is not able to meet load, there are four resource adequacy metrics that are calculated: LOLH, EUE, LOLEV, and LOLP (defined in Table below). These metrics are used to quantify and compare RA of proposed portfolios under the various scenarios. For analysis, these metrics are calculated on an individual monthly basis, and are thus denoted MoLOLH, MoEUE, MoLOLEV, and MoLOLP. Because performing a detailed analysis on each month of the year was computationally infeasible given current resources, this IRP considers only the months that would most likely be the least-adequate: July and August for the summer, and January and December for the winter. January and December were picked because historically City Light has been a winter-peaking utility. July and August are picked because City Light gets most of its power from hydroelectric dams, which has very low generation during the summer due to low water supply. Therefore, summer power needs usually must be supplemented with market purchases. Additionally, the retirement of regional base load plants (gas and coal) increases concerns that the summer power markets will be less reliable across the Pacific Northwest because of its high reliance on hydropower.

The term “expected” in Table 1 is determined by dividing each of the respective metrics and months by the total number of simulations by specific month. For example, if in a specific scenario there are 1,170 simulations that result in 1,170 instances of total unserved energy amounts in July, the resulting mean is the MoEUE for July. Furthermore, a loss of load probability is defined as the number of deficit hours in each month divided by the total number of hours in that month.

Table 1 RA Metrics Computed by HYDRRA Model

RA Metric	Description
MoLOLH	Expected loss of load hours per month (units of hours)
MoEUE	Expected total unserved energy per month (units of megawatt hours)
MoLOLEV	Expected number of events per month (units of count)
MoLOLP	Expected loss of load probability per month, defined as the probability of at least one shortfall in that month (units of percentage probability)

City Light Preferred RA Metric

As part of the 2020 IRP Progress Report, the Resource Planning Forecast & Analysis (RPFA) team received approval from the Risk Oversight Council (ROC) to update the primary RA metric for the IRP. The ROC has the authority, responsibility, and oversight function to lead City Light’s energy risk management efforts. As a result, the IRP adopted the metric of 0.2 for MoLOLEV, which is equivalent to an average of two deficit events every 10 years for each of the months of January, July, August, and December for all year-long simulations in a given scenario ensemble. Any shortfall less than 5 MW in any hour is excluded from being a deficit. A deficit event is defined as a period of consecutive hours where the sum total of City Light’s system-wide energy obligations, including loads, contracts, and exchanges, is greater than available energy supply by a pre-defined amount. For all weekdays of all calendar months except July and August, a deficit event is one that lasts longer than 4 hours (any size) or whenever one or more single-hours within the event has a deficit that is 200 MW- hours or more. For the months of July and August, less flexibility was assumed than in other months based on the typically low water conditions during those months. Similarly, for weekend days during all months, less flexibility was assumed due to longer day-ahead planning horizons for weekend energy market activity. Thus, during weekends and during the full months of July and August, a deficit event is defined as any period of an hour or more where any magnitude energy deficit occurs. The previous resource adequacy metric was 10% MoLOLP evaluated only in winter months January and December.

All 2022 IRP portfolios use the MoLOLEV metric to build portfolios that meet a specified adequacy standard on a monthly basis for the specific months of January, December, July, and August. For the 2022 IRP, it is assumed that for the years 2022 through 2025 City Light's power marketing team would be able to achieve resource adequacy with forward trading and other short-term options.

Descriptive Statistics of Resource Adequacy in Different Portfolios

Portfolios were evaluated through statistical analysis of the MoLOLEV study metric, including the calculation of means, standard deviations, and maximum values, for the scenarios discussed above, for the months of January, July, August, and December for the years 2030 and 2040. For each scenario, comparisons were drawn between each portfolio's performance and the 2022 IRP Baseline result.

To gain a better understanding of the resource adequacy of each portfolio, the same calculations were done using MoEUE, MoLOLH, and MoLOLP. However, as City Light's resource adequacy preferred metric is 0.2 MoLOLEV, only MoLOLEV was used for portfolio selection.

2022 IRP Top Seven Portfolios

As part of the 2022 IRP, seven portfolios were identified as top performing under the 2022 IRP Baseline scenario. Each of these portfolios were built under different strategies to determine a robust portfolio, as identified in Appendix 5: Create Top Portfolio. The names of the portfolios are in Table 2 below.

Table 2 2022 IRP Top Portfolios and Descriptions

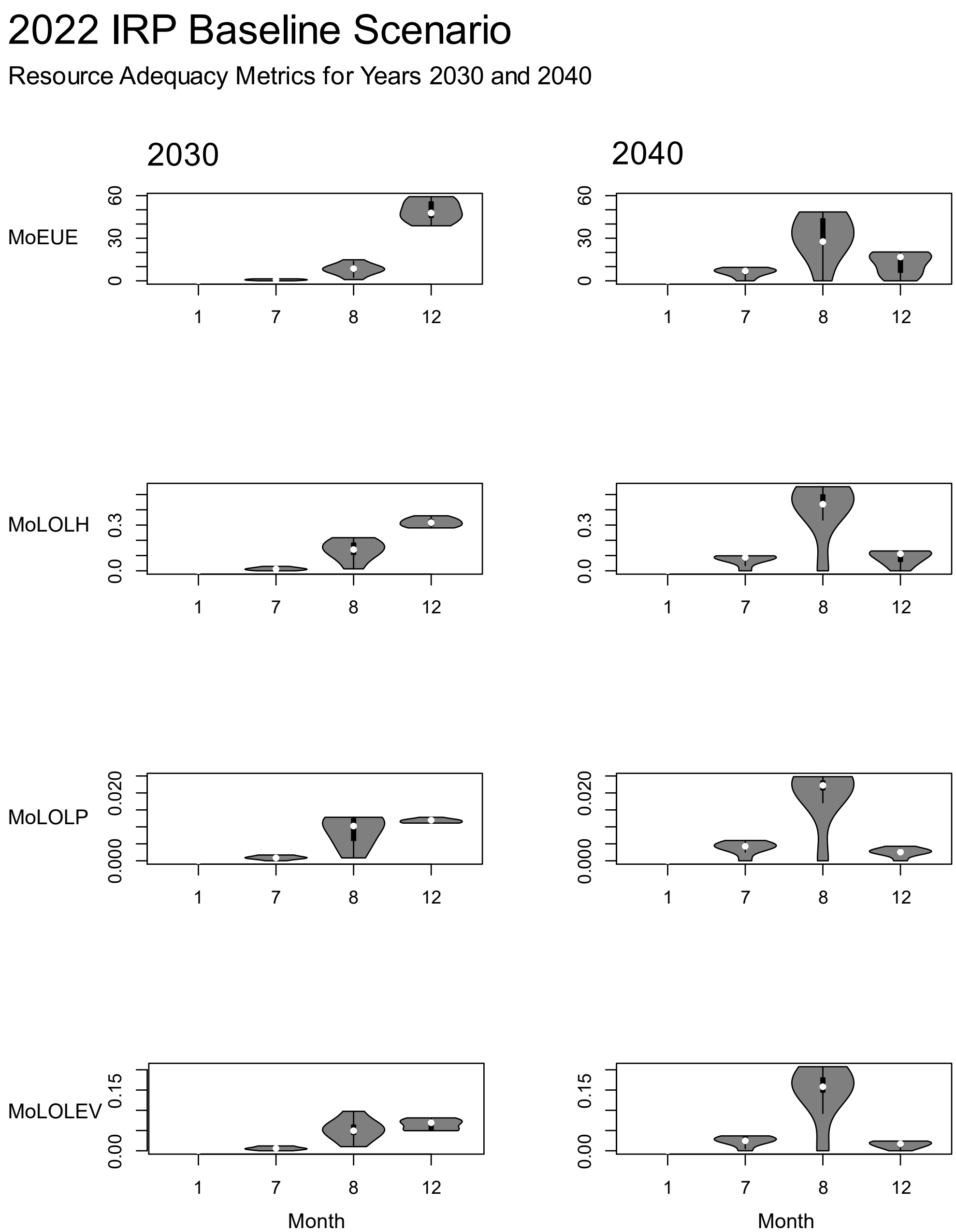
Portfolio	Description
P1: LowestCost	Base Lowest Cost
P6: 2DR	Base Lowest Cost + 2 Demand Response
P7: 4DR	Base Lowest Cost + 4 Demand Response
P11: Balanced	Base Lowest Cost + 2 Demand Response + Customer Solar
P34: 2032 Elect	Base Lowest Cost + 2032 Electrification Loads Begin
P35: HighEE	Base Lowest Cost + High Energy Conservation
P36: Solar + Batt	Base Lowest Cost + Utility Scale Solar with Battery

2022 IRP Baseline

The 2022 IRP Baseline scenario uses the 2020 City Light system load forecast architecture with 1,170 permutations of historical temperatures and historical water supply conditions. Hourly temperatures of the 30-year period from 1990 to 2019 are used to shape load forecast years. A 30-year time period is the typical period for calculating climate normals, as chosen by the governing body of international meteorology in the 1930s.[9] The historical water supply years are drawn from a 39-year period from 1981 to 2019. This timeframe was selected to represent the most reliable and available datasets. Each combination of historical water and historical temperature are sampled for each forecast year individually. Forecast years 2030 and 2040 were selected for in-depth RA analysis across the different scenarios and portfolios for consistency. This was because the climate change scenarios only contained years 2026, 2030, and 2040. Furthermore, most new portfolio resource additions happen in the mid to late 2020s, and it was important to analyze RA metrics for a complete portfolio of resources.

[9] For more information on climatic normals from the World Meteorological Organization (WMO, 2017), see: https://library.wmo.int/index.php?lvl=notice_display&id=20130#.Yr9EMpfMKUl.

Figure 1 Aggregate performance of seven 2022 IRP Portfolios for forecast years 2030 & 2040 under 2022 IRP Baseline with MoEUE, MoLOLH, MoLOLP, and MoLOLEV RA metrics



All seven 2022 IRP top candidate portfolios were designed to achieve an MoLOLEV of 0.2 or less. Of the two winter months considered in 2030, December has the largest MoLOLEV and MoEUE, but still falls below City Light's primary RA criterion. Of the two summer months evaluated in 2040, August has the largest MoLOLEV and MoEUE but it still meets the primary criterion.

In the 2022 IRP Baseline, the portfolios in 2030 have more difficulty meeting RA needs in December. This is due to assumed insufficient transmission required to gain access to Montana wind resources before 2032. By 2040, the portfolios have more difficulty meeting summer needs due to increased electrification loads.

Climate Change Scenarios

Introduction

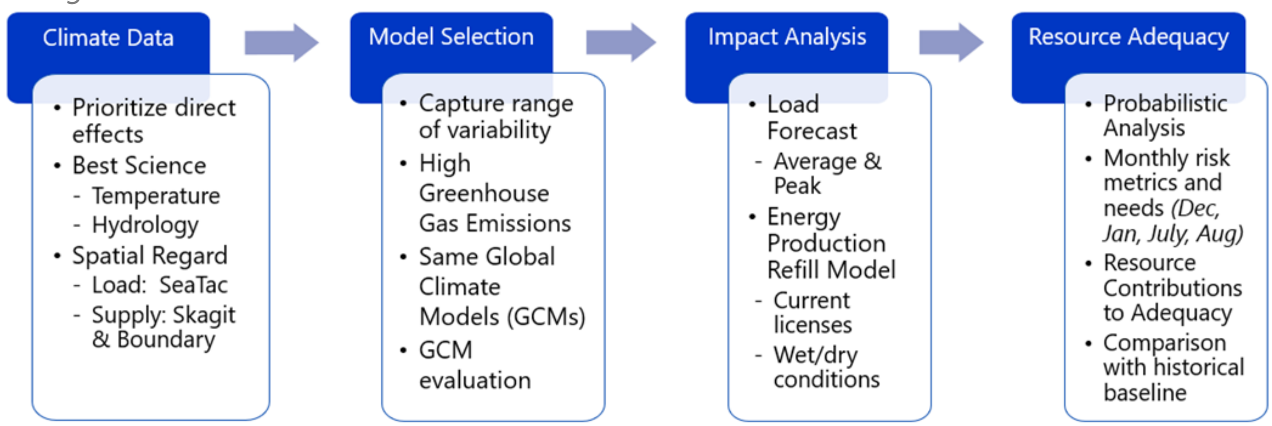
In 2016, City Light conducted a preliminary review and analysis of climate change impacts on energy demand and water resources in its 2016 IRP. At that time, City Light found that impacts from climate change in the near term (e.g., up to 2035) were within the range of variability of experiences from severe weather, market fluctuations, and emergency circumstances. Since then, new modeling has emerged that provides finer temporal and spatial resolution of projected changes in temperatures and streamflow. A major advancement in the 2022 IRP is City Light's development of climate change scenarios with the most credible climate change science available, which allow comparison with baseline conditions.

In this section, we briefly describe the climate datasets and the methods for selecting representative future conditions for our climate change base load scenarios. In order to evaluate how well the top seven portfolios may perform with the changing temperature and streamflow, those resource portfolios were run using two climate change scenarios carefully selected from a range of available future projections. The climate change scenarios modify both the distribution of energy supply as a result of variable water conditions at City Light's hydroelectric plants, and customer demand or load.

About the Data

In the 2022 IRP, City Light focused on assessing the direct effects of changes in climate, specifically temperature and streamflow, on energy demand and supply. This assessment used the best available climate change datasets that were readily available from credible sources (e.g., universities), appropriate for the load and hydrogeneration locations managed by City Light, and commonly used for climate change studies within the Pacific Northwest (see Figure 2). Because of the large quantity of climate change modeling that meets these criteria and the limited computational capacity, City Light carried out a series of narrowing approaches to limit the number of representative future conditions to assess RA under a climate change scenario. A modeling selection process began by choosing the same GCMs that provided data at the geographic disparate locations and focusing on a high greenhouse gas emissions scenario. The climate change datasets were then investigated to understand the range of variability and uncertainties. Final climate change datasets were narrowed down to two GCMs, CanESM2 and CCSM4, that captured local median and extremes in temperature and streamflow. These two modeled future conditions were analyzed using both load forecasting and energy production refill models as well as the HYDRRA tool to assess RA. More details on the climate change datasets and model selection can be found in Appendix 7: Climate Change.

Figure 2 Illustration of the workflow for assessing resource adequacy under a climate change scenario

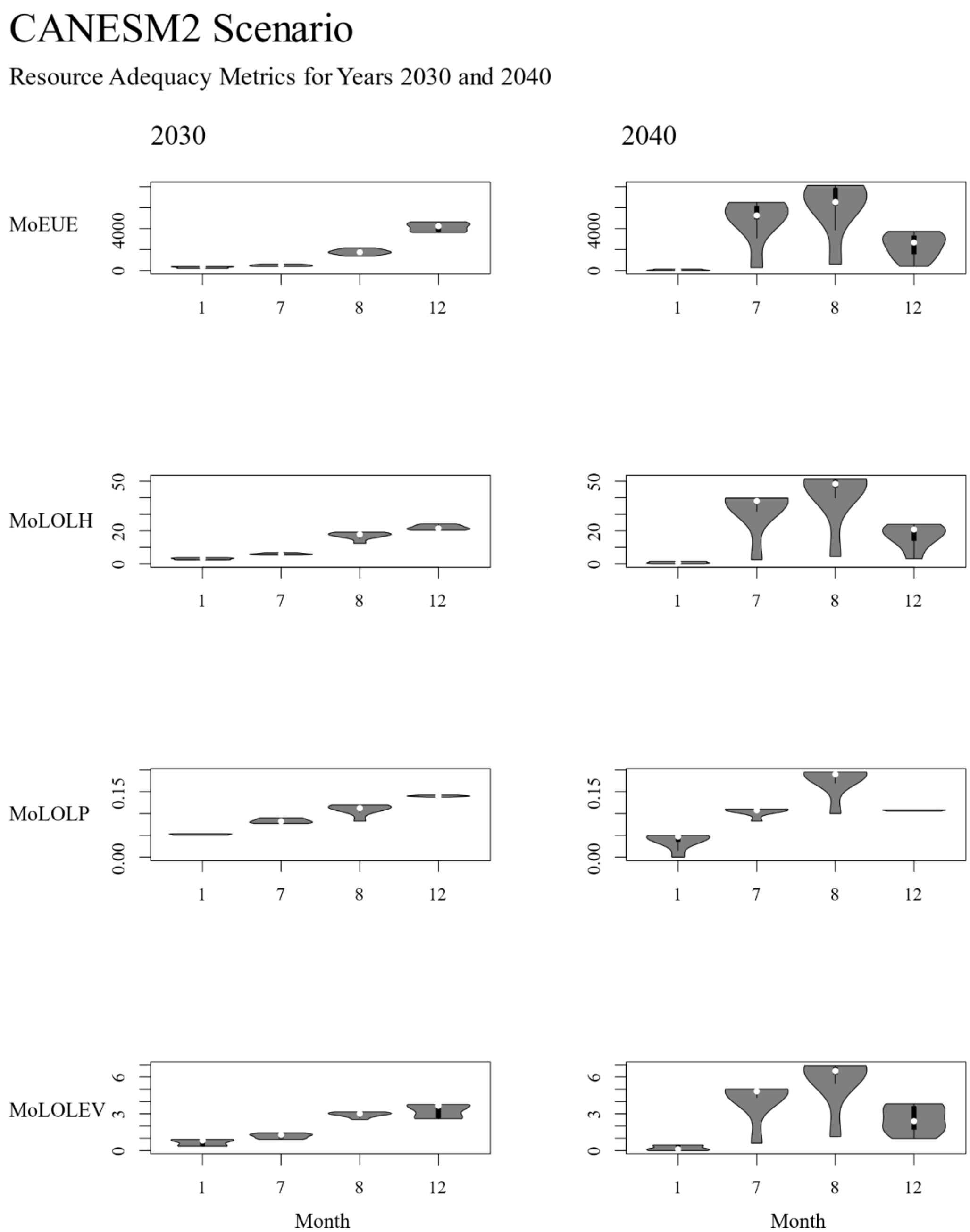


CanESM2 data are produced by the Canadian Centre for Climate Modeling and Analysis, Canada, and CCSM4 data are generated by the National Center for Atmospheric Research, USA. These two GCMs were found to be among the best performers at modeling historical observations among GCMs in the Pacific Northwest (Rupp et al. 2013). Compared to other models, CanESM2 has the strongest warming signal in summer. Additionally, a winter cold-bias among the GCMs was less pronounced in these two selected GCMs. While both CanESM2 and CCSM4 project higher flows during the cold season with earlier peak flows and lower summer flows than historically, CCSM4 is generally wetter during winter and spring and drier in the summer than CanESM2.

Resource Adequacy Results

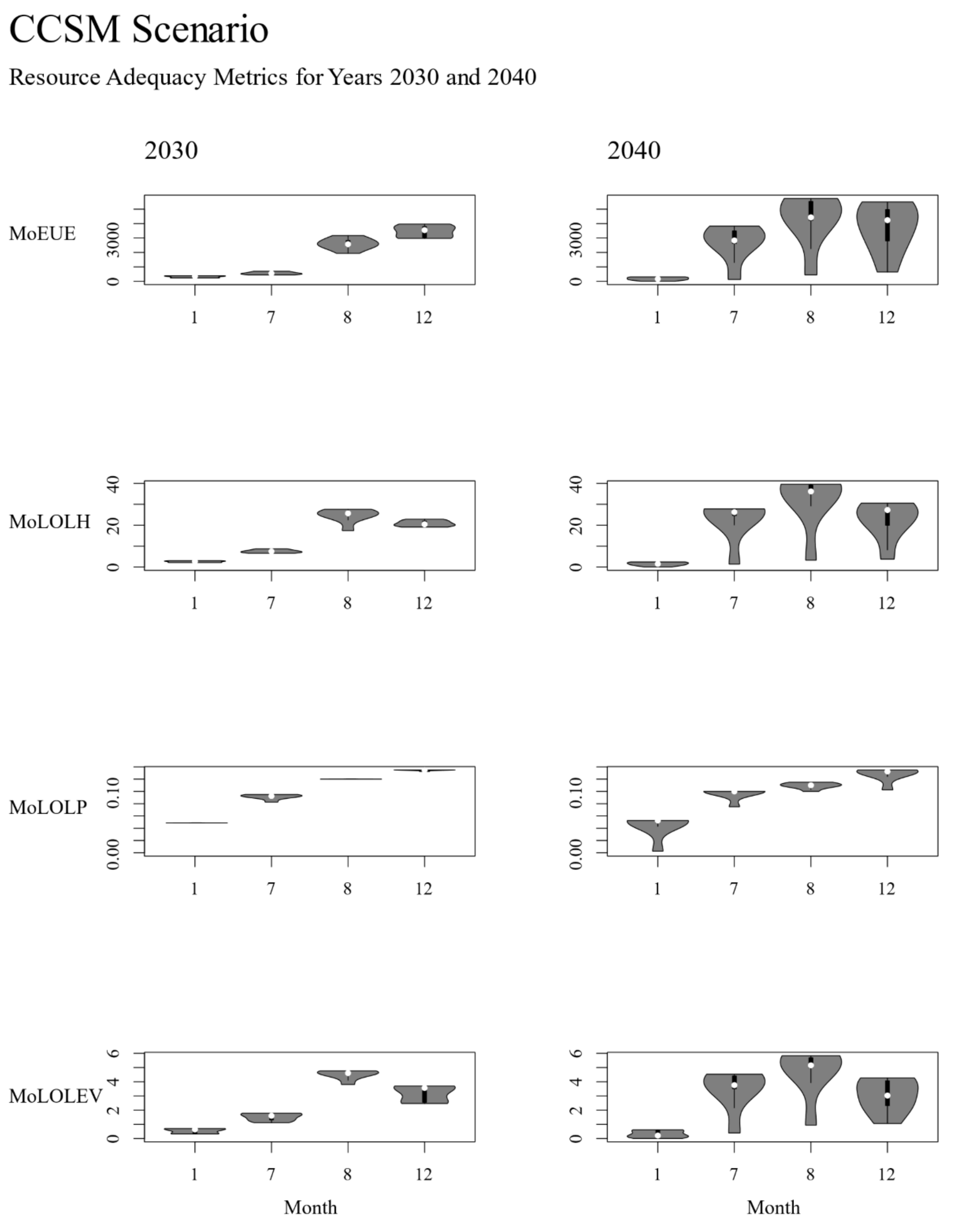
In 2030, the 0.2 MoLOLEV metric criterion was not met in any of the months (summer or winter) for the CanESM2 scenario (Figure 3). January performs the best where the MoLOLEV is the smallest, followed by July, then August, with December being the worst performing month. The distribution of August and December MoLOLEV data is similar, yet by looking at the MoEUE, one can see that the events in December are more severe compared to the events in August. In 2040 the 0.2 MoLOLEV metric criterion is again not met in any of the months. January is still the month with the least need, the second-best month becomes December, followed by July, and then August being the worst month. Thus, CanESM2 model shows that the summer poses a greater reliability threat for City Light, with both July and August having high MoLOLEV and MoEUE.

Figure 3 Aggregate performance of seven 2022 IRP Portfolios for forecast years 2030 & 2040 under CanESM2 with simulated load and hydro with MoEUE, MoLOLH, MoLOLP, and MoLOLEV RA metrics



For the CCSM4 scenario in 2030, the 0.2 MoLOLEV metric criterion is also not met in any of the summer or winter months (Figure 4). January is the best performing month, then July, followed by December, and the worst performing month is August. Although August has a higher MoLOLEV median than December, by looking at the MoEUE, one can see that the distribution of December unserved energy’s range is larger than in August. This can imply that the MoLOLEV metric by itself might provide a bad signal; a larger median MoLOLEV metric can have many smaller events (e.g., January), vs a smaller number of larger events (e.g., December). For 2040, January is still the best month, then December, followed by July, and the worst month is August. The MoEUE metric tells a similar story as 2030, showing that the December events are larger compared to the July events, and very similar to the August events. With the exception that the August distribution hast mostly severe events, while December has both small and large events by looking at the distribution of expected unserved energy. However, December ranks the second best given the MoLOLEV criterion.

Figure 4 Aggregate performance of seven 2022 IRP Portfolios for forecast years 2030 & 2040 under CCSM4 with simulated load and hydro with MoEUE, MoLOLH, MoLOLP, and MoLOLEV RA metrics



Results

Overall, by looking at the aggregate results of the 2022 IRP Baseline, CanESM2, and CCSM4 models, none of the top seven 2022 IRP portfolios adequately meet the RA requirements under the climate change scenarios. Both the CanESM2 and the CCSM4 results show that, by following City Light's established metric of 0.2 MoLOLEV, the summer months (July/August) perform the worst. Notable is that both models in 2030 show that the MoEUE is greater in December, but by 2040 both the MoEUE and MoLOLEV are consistently the highest in the summer. This finding is important to highlight as City Light may consider establishing additional RA metrics for future resource planning. Table 3 details the top seven portfolios and their MoLOLEV climate change rankings by color.

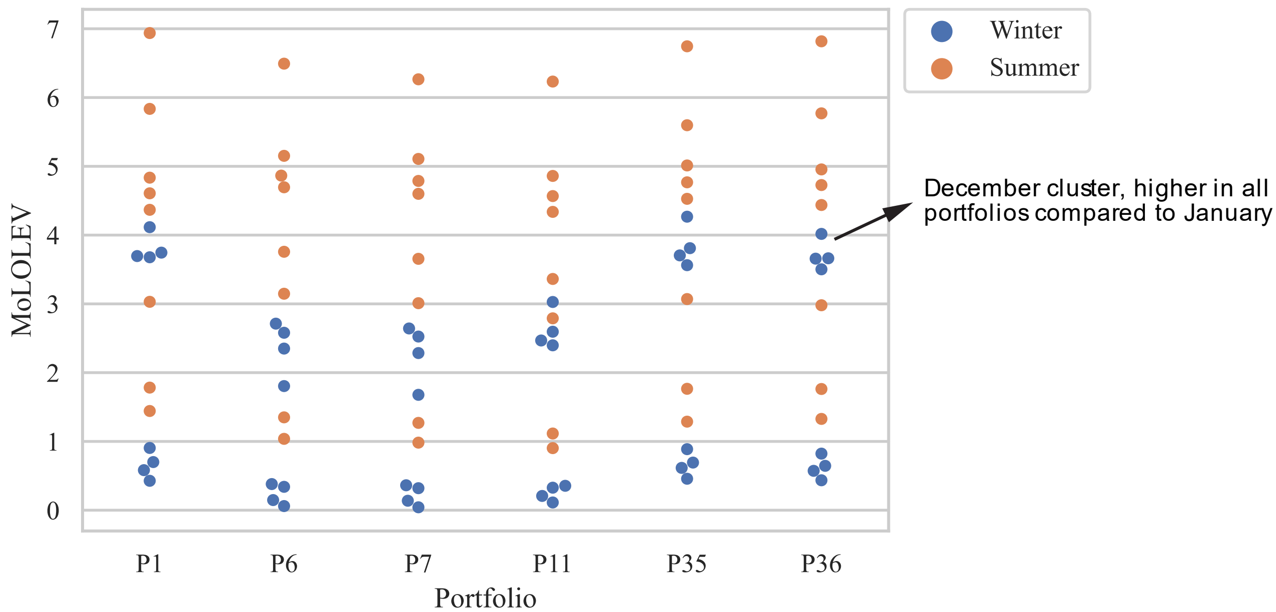
Table 3 Climate Change MoLOLEV Statistics

Portfolio	Mean	Standard Deviation	Maximum
P1	3.168	1.995	6.938
P6	2.555	2.000	6.493
P7	2.479	1.961	6.265
P11	**2.479**	**1.880**	**6.233**
P34	1.447	1.260	3.800
P35	3.173	1.988	6.745
P36	3.131	2.002	6.818

Table 3 shows the final statistics used to help select a top portfolio. P34 comes the closest to meeting resource adequacy of all the portfolios, but the mean MoLOLEV is still higher than the maximum of 0.2 required to be considered resource "adequate". P34 is a portfolio that is specifically built to meet the load within the Rapid Market Advancement electrification future starting in 2032, which requires more study before it can be considered viable. Because of this, P34 was discarded when choosing a top portfolio and the following tables and figures do not include this portfolio.

Within the remaining portfolios, P11 has the best projected resource adequacy for the climate change scenarios. It has the lowest mean and lowest maximum MoLOLEV, as well as the lowest standard deviation, meaning it has less variability in its resource adequacy than the other top portfolios (Figure 5).

Figure 5 All values for MoLOLEV under CanESM2 and CCSM4 scenarios by portfolio and season



Note that the MoLOLEV metric for City Light is 0.2, but the range of Figure 5 is 0-7. Winter has very consistent MoLOLEV values with the clusters of lower MoLOLEVs being in January and the larger clusters in December. The distribution of summer values is very similar for all portfolios, but much more spread out relative to the winter values. The summer values for P11 are shifted down the most out of all portfolios, but the winter values are slightly higher than they are for P6 and P7. P6 and P7 also have the most variability of all portfolios in December MoLOLEV (Figure 5).

Table 4 details the MoLOLEV means of the top seven portfolios in the 2022 IRP Baseline compared to the Climate Change scenarios.

Table 4 Comparing 2022 IRP Baseline and climate change MoLOLEV means

Portfolio	2022 IRP Baseline	Climate Change	Difference
P1	0.049	3.168	3.119
P6	0.040	2.555	2.515
P7	0.039	2.479	2.441
P11	0.035	2.479	2.444
P35	0.055	3.173	3.118
P36	0.041	3.131	3.090

Comparing the climate change resource adequacy metrics to 2022 IRP Baseline shows *how much* worse a portfolio performs if the climate change future occurs and City Light only prepares for the 2022 IRP Baseline (Table 4). For example, RA for P11 would be 71 times worse in the climate change scenarios with an average increase of about 2.44 MoLOLEV.

Table 5 Comparing 2022 IRP Baseline and climate change MoLOLEV standard deviations

Portfolio	2022 IRP Baseline	Climate Change	Difference
P1	0.063	1.995	1.932
P6	0.051	2.000	1.949
P7	0.049	1.961	1.912
P11	0.045	1.880	1.835
P35	0.069	1.988	1.919
P36	0.054	2.002	1.948

Comparing the standard deviations highlights the variability in RA by both scenario and portfolio (Table 5). This is an important element to consider, as, for example, P6 has a very similar mean MoLOLEV to the top portfolio P11, but it has much more variability, making it a worse portfolio in terms of resource adequacy. In addition, RA under climate change is much more variable, indicating the need for more flexible resources to meet the fluctuations, especially given the big difference between summer and winter, and even between winter months.

Below are additional RA Metric and Comparisons to MoLOLEV for Climate Change & 2022 IRP Baseline.

Table 6 All climate change statistics

	MoLOLEV		MoEUE		MoLOLH		MoLOLP	
Portfolio	**Mean**	**Std**	**Mean**	**Std**	**Mean**	**Std**	**Mean**	**Std**
P1	3.168	1.995	3032	2524	20.124	15.089	0.102	0.038
P6	2.555	2.000	2265	2008	18.082	14.537	0.101	0.040
P7	2.479	1.961	2166	1934	17.607	14.230	0.100	0.041
P11	2.479	1.880	2301	1957	17.999	13.907	0.101	0.039
P35	3.173	1.988	3041	2479	20.805	15.346	0.101	0.038
P36	3.131	2.002	2867	2430	19.691	15.123	0.100	0.037

Table 7 Portfolio rankings within each climate change statistic

MoLOLEV		MoEUE		MoLOLH		MoLOLP	
Mean	Std	Mean	Std	Mean	Std	Mean	Std
P11	P11	P7	P7	P7	P11	P36	P36
P7	P7	P6	P11	P11	P7	P7	P35
P6	P35	P11	P6	P6	P6	P11	P1
P36	P1	P36	P36	P36	P1	P6	P11
P1	P6	P1	P35	P1	P36	P35	P6
P35	P36	P35	P1	P35	P35	P1	P7

All four RA metrics are important in understanding the resource adequacy of a portfolio, but City Light has not yet set a standard of what is considered "good" for any metrics other than MoLOLEV. Because of this, it is helpful to see the overall picture of RA and where the chosen top portfolio (P11) falls.

P6, P7, and P11 have the best RA across all metrics except MoLOLP and the standard deviation of MoLOLEV. P11 has the best or second-best RA across all metrics except MoLOLP and the mean of MoEUE. In addition, P11 is best or second-best among P6, P7, and P11 for both MoLOLP statistics (Table 7). This supports P11 as a high-ranking portfolio even when using all four RA metrics. MoLOLP has the most unique ranking, likely since the differences between portfolios for this metric are much smaller allowing for chance to play a larger role.

Table 8 All statistics showing the difference between the 2022 IRP Baseline and climate change scenarios

	MoLOLEV		MoEUE		MoLOLH		MoLOLP	
Portfolio	**Mean**	**Std**	**Mean**	**Std**	**Mean**	**Std**	**Mean**	**Std**
P1	3.119	1.932	3014	2502	19.969	14.905	0.095	0.031
P6	2.515	1.949	2252	1993	17.938	14.373	0.093	0.032
P7	2.441	1.912	2154	1919	17.470	14.079	0.093	0.033
P11	2.444	1.835	2289	1943	17.867	13.756	0.094	0.032
P35	3.118	1.919	3022	2457	20.638	15.157	0.094	0.030
P36	3.090	1.948	2851	2410	19.559	14.966	0.094	0.030

Table 9 Portfolio rankings within each statistic

MoLOLEV		MoEUE		MoLOLH		MoLOLP	
Mean	**Std**	**Mean**	**Std**	**Mean**	**Std**	**Mean**	**Std**
P7	P11	P7	P7	P7	P11	P7	P35
P11	P7	P6	P11	P11	P7	P6	P36
P6	P35	P11	P6	P6	P6	P36	P1
P36	P1	P36	P36	P36	P1	P11	P11
P35	P36	P1	P35	P1	P36	P35	P6
P1	P6	P35	P1	P35	P35	P1	P7

Table 8 and Table 9 look at the difference between the statistics under the climate change scenarios and under baseline. The rankings are very similar to Table 7, with the only differences are with P7 and P11 switching for mean MoLOLEV; the top four portfolios shuffling for mean MoLOLP; and P35 and P36 switching for the standard deviation of MoLOLP. The statistics for MoLOLP are very similar, so random variation has more impact on the rankings.

P11 along with P6 and P7 have the best RA in almost every possible metric explored in this analysis. All three of these portfolios include the residential thermostat DR programs and the residential electric resistance water heating DR programs. These programs, therefore, appear to be strong attributes for portfolio improvement when compared to the rest of the portfolios that do not have those resources. P11 has the addition of Incremental Customer Solar which mainly benefits the summer, and it slightly improves the RA performance overall compared to P6 and P7.

Conclusion

As part of the 2022 IRP, City Light has explored possible future resource options and how they perform under two climate change scenarios, specifically the CanESM2 and CCSM4 GCMs. City Light has established climate change metrics that help clarify one of the important areas of risk and uncertainty to Seattle, given that its current fleet of resources is approximately 90% hydropower. This is a preliminary assessment of climate change impacts, and City Light still has more work to do to make climate change part of the baseline scenario. These are several takeaways from this work:

- Only two climate change scenarios were assessed in HYDRRA, although climate change experts recommend studying at least six climate change scenarios to get a well-represented distribution of possible futures (Brekke et al. 2006). City Light recognizes that the selected two climate change scenarios may not fully represent the range of future climate conditions.

- Additional analyses are needed to address ongoing uncertainties in (1) cold biases in projected future winter temperatures in GCMs that substantially affect load and (2) unknown operational flexibility in hydropower operations due to decarbonizing regulations, renewable integration, and current relicensing efforts.
- More research and work are needed to assess the hydro and load sampling windows; this is an area where City Light can look at different sampling alternatives and assess the impact to the RA results.
- Analysis of climate change impacts on energy load and hydropower supply indicated challenges in meeting resource adequacy within the next 20 years; however, resource acquisitions to support increased electrification should offset these challenges.
- The climate change and electrification scenarios were assessed separately in the 2022 IRP. City Light should consider the interaction between electrification and climate change in subsequent analyses.
- City Light needs a more robust RA metric(s) defined by each month. While City Light sets a limit of 0.2 MoLOLEV for January, July, August, and December, this metric can be misleading, and more metrics should be integrated as part of future portfolio evaluation.

Electrification

Introduction

City Light recently collaborated with the Electric Power Research Institute (EPRI) to complete an Electrification Assessment[10] focused on better understanding future electricity demand and availability distribution system capacity under three different scenarios: Moderate Market Advancement, Rapid Market Advancement, and Full Electrification. Within each scenario, electrification potential was broken down into transportation, buildings, and industry sectors. More information about underlying scenario assumptions can be found in the EPRI electrification assessment report.

The Rapid Market Advancement (RMA) was chosen to represent a more aggressive electrification scenario for the 2022 IRP. This scenario follows the city of Seattle's climate action plan which is to achieve zero net greenhouse gas emissions by 2050 and has much more load growth as compared to the 2022 IRP Baseline. To achieve this level of

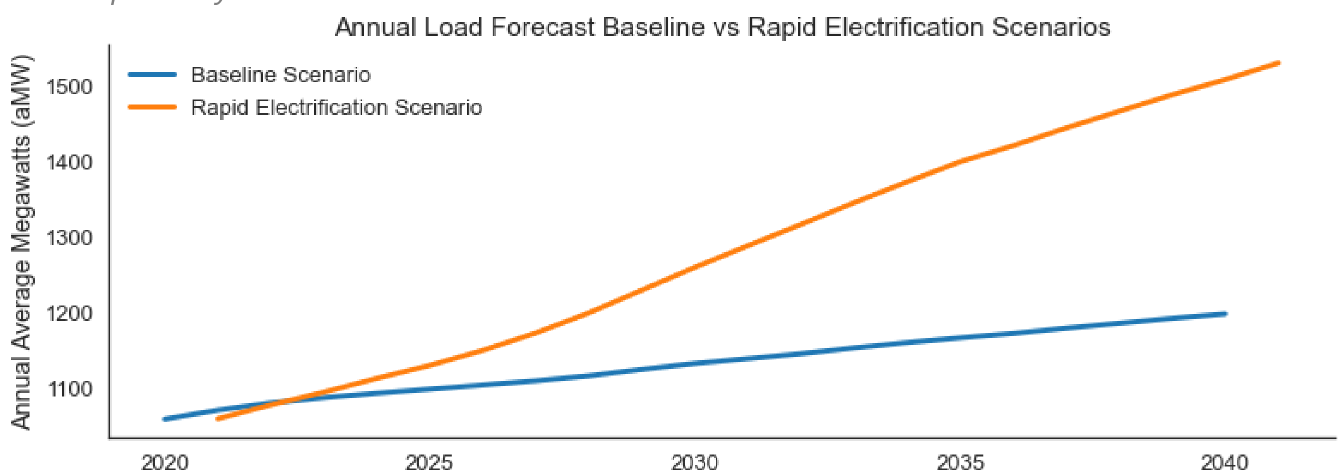
[10] https://powerlines.seattle.gov/wp-content/uploads/sites/17/2022/01/Seattle-City-Light-Electrification-Assessment.pdf.

electrification, additional policy and funding mechanisms would be required at the local, state, and federal level to encourage decarbonization above and beyond what is projected in the EPRI Moderate Market Advancement scenario.

About the Data

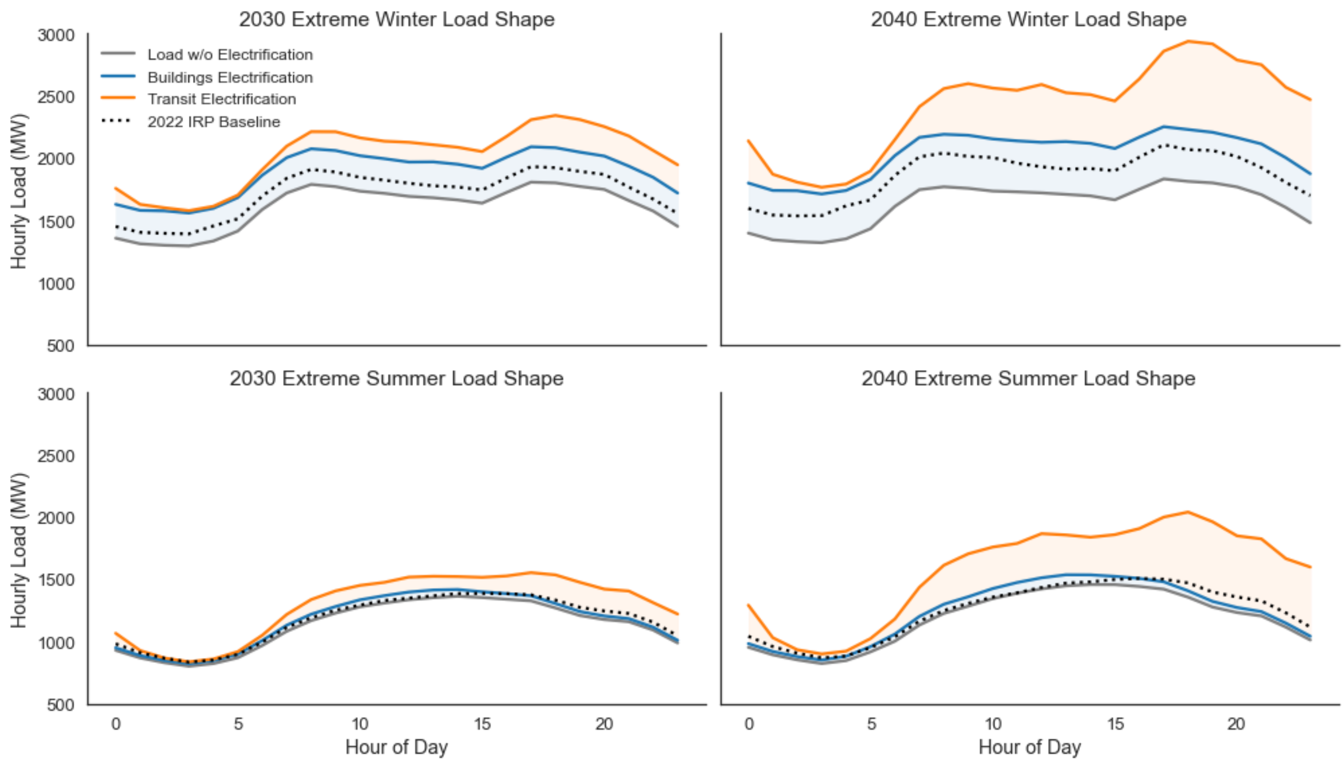
The Electrification RMA scenario from the Electrification Assessment is used to layer additional new transportation and building related electrification loads onto the 2022 IRP Baseline load forecast. Annual average energy is about 26% higher in 2040 under the Electrification RMA scenario relative to the 2022 IRP Baseline scenario as shown in Figure 6 below.

Figure 6 Forecast of annual energy in average MW (aMW) from 2020 to 2041 for the 2022 IRP Baseline and Electrification RMA scenarios colored using the blue and orange solid lines respectively



RA performance is heavily influenced by extreme cold and heat event load conditions. The impacts of more aggressive electrification on load are not constant throughout the year. Electrification in the buildings sector is primarily driven by conversion of natural gas space and water heating to heat pump equipment. Heat pumps operate less efficiently at colder temperatures and can also sometimes rely on electric resistance for auxiliary heating requirements. For this reason, buildings related electrification has a significantly more pronounced impact on winter peak loads than summer. Transportation electrification is generally more constant throughout the year but does impact the daily load shape by increasing evening peaks relative to the baseline. Figure 7 below shows the impact that electrification has on extreme winter and summer shapes relative to the baseline load scenario.

Figure 7 Predicted hourly load shape under extreme weather conditions for winter and summer seasons



The dotted grey line in Figure 7 shows the hourly load shape for the 2022 IRP Baseline load forecast. The solid grey line shows the hourly load shape without any electrification. The solid blue line and shaded area represents additional load from buildings electrification. The orange line and shaded area represents additional load from transit electrification.

Results

The 2022 IRP top seven portfolios were all run through the resource adequacy model using the Electrification RMA loads. A table (Table 10) of statistics was created based on the MoLOLEV raw data from July, August, January, and December for the years 2030 and 2040.

Table 10 Electrification RMA scenario MoLOLEV statistics and ranking

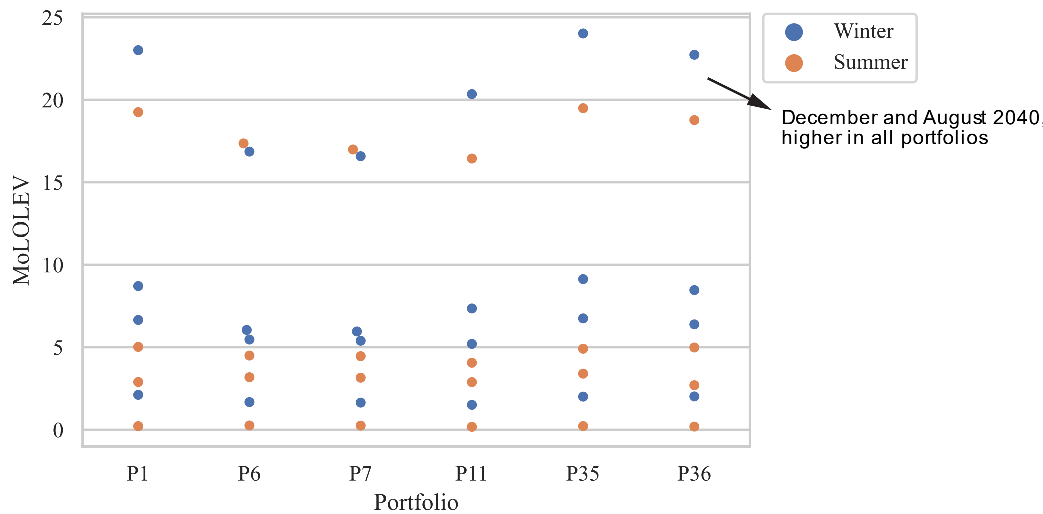
Portfolio	Mean	Standard Deviation	Maximum
P1	8.483	8.302	23.006
P6	6.917	6.572	17.357
P7	6.801	6.441	16.987
P11	**7.245**	**7.294**	**20.344**
P34	1.175	1.719	5.170
P35	8.740	8.571	24.020
P36	8.279	8.186	22.729

Table 10 shows the final statistics used to help select a top portfolio, except the portfolios were run using the Electrification RMA scenario. P34 comes the closest to meeting RA as compared to the other portfolios, however the mean MoLOLEV is still higher than the maximum of 0.2 required to be considered "adequate". P34, however, is a portfolio that is specifically built to best meet the load withing the RMA future starting in 2032, and thus will always have the best RA when looking at the Electrification RMA scenario. Because of this, the following tables and figures do not include this portfolio in order to better compare the remaining top portfolios.

Within the remaining portfolios, P6 and P7 have the best projected resource adequacy for the Electrification RMA scenario. This is contrary to the climate change scenarios, where P11 has the best RA. This is because the climate change scenarios show a higher summer need (which P11 caters to by having the Incremental Customer Solar program), whereas the Electrification RMA scenario shows a higher winter need that is met better by the additional 25 MW of Montana wind that P6 and P7 have as compared to P11.

Even with the reduced winter supply in P11, the portfolio has a mean MoLOLEV only 6.5% higher than that of P7 and the standard deviation is 13% higher. The maximum MoLOLEV is 20% higher, which is solely due to P11's lacking resources in December 2040.

Figure 8 All values for MoLOLEV under Electrification RMA scenario by portfolio and season



Note that in Figure 8 the MoLOLEV metric for City Light is 0.2, but the range of this graph is 0-25.

Winter is generally higher than summer, but summer still has poor resource adequacy. The highest winter values for each portfolio are from December 2040, and the highest summer values are from August 2040. P6 and P7 have the best RA overall and especially in December 2040, however P11 has slighter lower MoLOLEV values for every summer month once again due to the higher summer focus of this portfolio.

Table 11 Comparing 2022 IRP Baseline and Electrification RMA MoLOLEV means

Portfolio	**2022 IRP Baseline**	**Electrification RMA**	**Difference**
P1	0.049	8.483	8.434
P6	0.040	6.917	6.877
P7	0.039	6.801	6.763
P11	0.035	**7.245**	**7.210**
P35	0.055	8.740	8.685
P36	0.041	8.279	8.238

Comparing the Electrification RMA scenario RA metrics to the 2022 IRP Baseline in Table 11 shows how much worse a portfolio performs if the Electrification RMA future occurs and City Light only prepares for the 2022 IRP Baseline. For example, RA for P11 would be more than 200 times worse in the Electrification RMA scenario with an average increase of about 7.2 MoLOLEV. The portfolio rankings using the difference in mean between the 2022 IRP Baseline and Electrification RMA scenario gives about the same results as just using the means; the only differences are that P11 is better than P6 and P7 under the 2022 IRP Baseline, but worse under Electrification RMA.

Table 12 Comparing 2022 IRP Baseline and Electrification RMA MoLOLEV standard deviations

Portfolio	2022 IRP Baseline	Electrification RMA	Difference
P1	0.063	8.302	8.239
P6	0.051	6.572	6.521
P7	0.049	6.441	6.392
P11	**0.045**	**7.294**	**7.249**
P35	0.069	8.571	8.502
P36	0.054	8.186	8.133

Comparing the standard deviations highlights the variability in RA by both scenario and portfolio. RA under electrification is much more variable, showing the need for more flexible resources to meet the fluctuations and higher energy amounts. Between portfolios, the ranking is the same as the mean MoLOLEV in Table 12.

Additional portfolio RA metrics, statistics, and rankings are shown in Table 13 and Table 14.

Table 13 All Electrification RMA statistics

	MoLOLEV		MoEUE		MoLOLH		MoLOLP	
Portfolio	Mean	Std	Mean	Std	Mean	Std	Mean	Std
P1	8.483	8.302	13461	17235	51.144	57.542	0.445	0.312
P6	6.917	6.572	10258	12429	45.578	48.644	0.441	0.301
P7	6.801	6.441	10005	12158	45.092	48.222	0.440	0.301
P11	7.245	7.294	11685	15871	49.769	58.434	0.440	0.320
P35	8.740	8.571	13865	18173	53.437	60.868	0.447	0.316
P36	8.279	8.186	12968	16759	49.891	56.458	0.436	0.313

Table 14 Portfolio rankings within each Electrification RMA statistic

MoLOLEV		MoEUE		MoLOLH		MoLOLP	
Mean	**Std**	**Mean**	**Std**	**Mean**	**Std**	**Mean**	**Std**
P7	P7	P7	P7	P7	P7	P36	P7
P6	P6	P6	P6	P6	P6	P7	P6
P11	P11	P11	P11	P11	P36	P11	P1
P36	P36	P36	P36	P36	P1	P6	P36
P1	P1	P1	P1	P1	P11	P1	P35
P35	P35	P35	P35	P35	P35	P35	P11

All four RA metrics are important in understanding the resource adequacy of a portfolio, but City Light has not yet set a standard of what is considered "good" for any but MoLOLEV. Because of this, it is helpful to see the overall picture of RA and where the chosen top portfolio (P11) falls.

P6, P7, and P11 have the best RA across all metrics but MoLOLP and the standard deviation of MoLOLH. P11 has the third-best RA across all metrics (generally behind P6 and P7) except for the standard deviation of both MoLOLH and MoLOLP; in those two metrics, P11 comes last or second-to-last due to low MoLOLH and MoLOLP values in summer and extremely high values in December 2040. This supports P11 as a high-ranking portfolio even when using all four RA metrics, while also highlighting the need for additional winter resources if electrification advances quickly.

Table 15 All statistics showing the difference between the 2022 IRP Baseline and Electrification RMA scenarios

	MoLOLEV		MoEUE		MoLOLH		MoLOLP	
Portfolio	**Mean**	**Std**	**Mean**	**Std**	**Mean**	**Std**	**Mean**	**Std**
P1	8.434	8.239	13443	17213	50.988	57.358	0.438	0.305
P6	6.877	6.521	10246	12413	45.435	48.480	0.434	0.293
P7	6.763	6.392	9994	12143	44.955	48.071	0.432	0.293
P11	7.210	7.249	11673	15857	49.638	58.283	0.434	0.312
P35	8.685	8.502	13847	18152	53.270	60.679	0.440	0.308
P36	8.238	8.133	12952	16739	49.759	56.301	0.431	0.306

Table 16 Portfolio rankings within each statistic

MoLOLEV		MoEUE		MoLOLH		MoLOLP	
Mean	Std	Mean	Std	Mean	Std	Mean	Std
P7	P7	P7	P7	P7	P7	P36	P7
P6	P6	P6	P6	P6	P6	P7	P6
P11	P11	P11	P11	P11	P36	P6	P1
P36	P36	P36	P36	P36	P1	P11	P36
P1	P1	P1	P1	P1	P11	P1	P35
P35	P35	P35	P35	P35	P35	P35	P11

Table 15 and Table 16 look at the differences between the statistics under the Electrification RMA scenario and under the 2022 IRP Baseline scenario. The rankings are very similar to Table 14; the only difference is P6, P11, and P1 shuffling for the mean MoLOLP. The statistics for MoLOLP are very similar, so random variation has more impact on the rankings.

P11 along with P6 and P7 have the best resource adequacy in almost every possible metric explored in this document. All three of these portfolios include the residential thermostat DR program and the residential electric resistance water heating DR program. These DR programs therefore appear to be strong attributes for portfolio improvement when compared to the rest of the portfolios that do not have those resources.

Conclusion

Electrification will certainly increase demand for electricity, and more resources will be needed to meet these loads in order to maintain sufficient levels of RA. The 2022 IRP top seven portfolios evaluated were not designed to meet the Electrification RMA scenario's loads. P34 does meet the needs described in the Electrification RMA scenario after 2032 but does not take climate change into consideration. Currently, in order to meet Electrification RMA loads, transmission constraints would have to be relaxed in the late 2020s to build a resource adequate portfolio for this scenario.

While additional work needs to be done in order to more accurately model future loads due to electrification and climate change, this preliminary work by City Light indicates that:

- Electrification results in higher winter loads, which wind and some demand response resources are better for meeting, as shown in P6, P7, and P11.
- There is also much more variability in RA under electrification futures, showing the need for more flexible resources to meet the fluctuations. City Light should look for resources that have more winter flexibility given the expectation of future electrification loads.
- While P11 is not the top portfolio for the Electrification RMA scenario, it still makes the top three, and it has other important attributes such as relying less on transmission and having more resource diversity as compared to P6 and P7.

P11 Top Portfolio Sensitivity Analysis

Introduction

City Light's 2022 IRP top portfolio (P11) meets RA requirements while performing best overall in terms of the broader range of metrics considered (cost, emissions, customer programs, etc.) under the 2022 IRP Baseline scenario. However, City Light must also consider the potential impact if the portfolio were to underperform, or if resources could not be acquired as planned. To address this, seven different new portfolios were created based on P11 that implement a 20% reduction on different sets of resources and were assessed on how well they meet City Light's RA standard of a maximum 0.2 MoLOLEV.

About the Data

P11 is a diverse portfolio comprising resources as shown in the tables below. Note the tables do not include City Light's owned generation resources or the long-term power purchase contracts that supplement the BPA block contract.

Table 17 2022 IRP Top Portfolio (P11) resource allocation in 2030

Year	Resource	aMW	Percentage
2030	BPA (aMW)	414.7	63.4%
2030	Large Customer Renewable Placeholder (aMW)	30.0	4.6%
2030	DR (aMW)	10.8	1.6%
2030	EE (aMW)	79.1	12.1%
2030	Solar (aMW)	20.8	3.2%
2030	Wind (aMW)	94.5	14.5%
2030	Incremental Customer Solar (aMW)	3.9	0.6%

Table 18 2022 IRP Top Portfolio (P11) resource allocation in 2040

Year	Resource	aMW	Percentage
2040	BPA (aMW)	443.5	59.0%
2040	Large Customer Renewable Placeholder (aMW)	30.0	4.0%
2040	DR (aMW)	17.4	2.3%
2040	EE (aMW)	114.4	15.2%
2040	Solar (aMW)	20.8	2.8%
2040	Wind (aMW)	117.6	15.7%
2040	Incremental Customer Solar (aMW)	7.4	1.0%

In order to investigate how reliant P11 is on the energy values listed in Table 17 and Table 18, the following portfolios were created in Table 19.

Table 19 Risk portfolio aliases and reduction in energy amount

Portfolio	Alias	Reduction
P11_Risk1	D_Cust_Solar	80% of Incremental Customer Solar
P11_Risk2	D_DR	80% of Demand Response
P11_Risk3	S_Wind	80% of Wind
P11_Risk4	S_Solar	80% of Supply-Side Solar
P11_Risk5	D_EE	80% of Energy Efficiency
P11_Risk6	S_Supply	80% of All Supply-Side Resources
P11_Risk7	D_Demand	80% of All Demand-Side Resources

The 'D' or 'S' prefix on the portfolio aliases refer to whether that resource or set of resources is supply-side ('S') or demand-side ('D'). In addition, the top portfolio P11 under the 2022 IRP Baseline will be used as a reference point and be referred to as 'Baseline'.

Table 20 Risk portfolio resource allocation in aMW

Portfolio	Alias	2030 aMW	2040 aMW
P11	Baseline	653.8	751.1
P11_Risk1	D_Cust_Solar	653.0	749.6
P11_Risk2	D_DR	651.6	747.6
P11_Risk3	S_Wind	634.9	727.6
P11_Risk4	S_Solar	649.6	746.9
P11_Risk5	D_EE	653.5	753.5
P11_Risk6	S_Supply	630.7	723.4
P11_Risk7	D_Demand	650.6	748.6

This shows that there is very little impact at a *yearly* level for D_Cust_Solar, D_DR, and D_EE. For D_EE and D_Demand, it is important to highlight that the BPA block contract energy is impacted by the load and EE interaction. All else equal, the higher the EE the lower the BPA block contract amount, and the lower the EE the higher the BPA block contract amount. The largest yearly impact is when all supply-side resources are reduced, as that makes up the largest portion of the 2022 IRP Baseline portfolio.

The results and ranking of the MoLOLEV risk assessment are shown in Table 21.

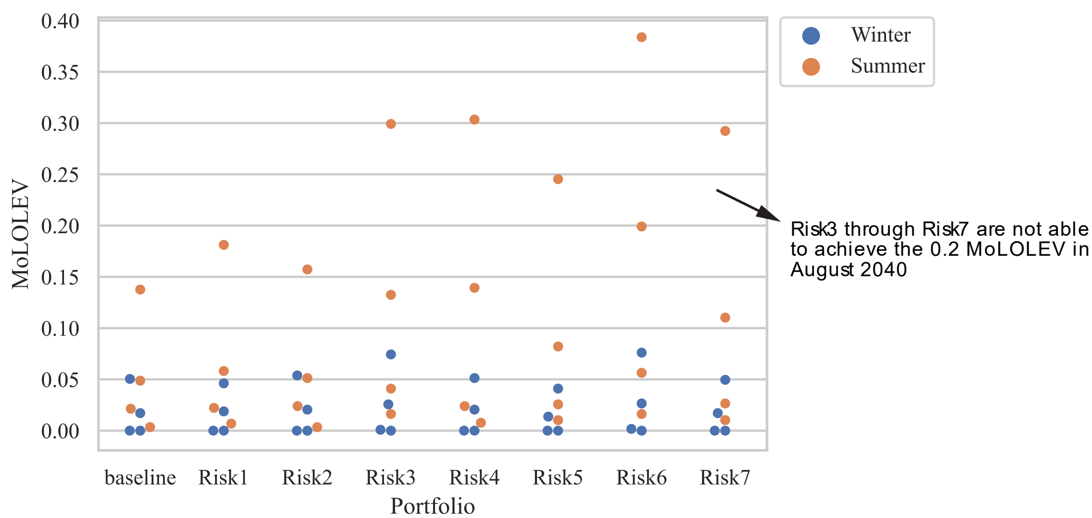
Table 21 Risk MoLOLEV statistics with 2022 IRP Baseline as a reference

Portfolio	Mean	Standard Deviation	Maximum
2022 IRP Baseline	0.035	0.045	0.138
D_Cust_Solar	0.042	0.060	0.181
D_DR	0.039	0.052	0.157
S_Wind	0.074	0.101	0.299
S_Solar	0.068	0.105	0.303
D_EE	0.052	0.083	0.245
S_Supply	0.095	0.133	0.384
D_Demand	0.063	0.099	0.292

Table 21 shows the same final statistics used to select a top portfolio. All risk portfolios meet the 0.2 MoLOLEV metric on average required to be considered “adequate”, however the maximum MoLOLEV is only met by D_Cust_Solar and D_Cust_Solar. All the other portfolios only fail this metric in August of 2040 (of the 4 months and 2 years included in this analysis). In all other months, even a 20% reduction in either demand or supply side resources is not enough to make the P11 portfolio fail to meet resource adequacy.

S_Supply has the worst RA by far of all the risk portfolios, with all metrics being more than double compared to the best portfolio D_Cust_Solar. This makes sense, as supply-side resources make up the bulk of the P11 portfolio and thus a 20% decrease has a large impact on the aMW. On the other hand, D_Cust_Solar and D_DR make up the smallest portion of the portfolio, so the percentage decrease has less of an effect.

Figure 9 All values for MoLOLEV for baseline P11 and risk portfolios by portfolio and season



All Winter values stay below 0.1, which is half of the maximum MoLOLEV required to be considered adequate. All values above that 0.1 are from August. In addition, all values above 0.2 (the cutoff for acceptable RA) as well as the highest MoLOLEV for each portfolio are from August 2040. This is true for the 2022 IRP Baseline as well, so it makes sense that the month that is already struggling slightly with RA fails to meet the required metric when energy amount is reduced.

Each portfolio has a different degree of impact in the Summer and Winter months. D_Cust_Solar and D_EE have slightly *lower* MoLOLEV values in December. S_Wind and S_Supply have noticeably worse RA in December 2030. Summer, specifically August, has much larger increases in MoLOLEV. This is very slight for D_DR and D_Cust_Solar, and only noticeable in 2040 for D_EE and D_Demand. S_Supply has the largest jump in

MoLOLEV with August 2040 being 0.25 higher than Baseline. S_Supply is also the only portfolio to have noticeably worse RA in both Winter and Summer.

Table 22 Comparing the 2022 IRP Baseline P11 portfolio and P11 risk portfolios MoLOLEV means

Portfolio	2022 IRP Baseline	Risk	Difference
D_Cust_Solar	0.035	0.042	0.007
D_DR	0.035	0.039	0.004
S_Wind	0.035	0.074	0.039
S_Solar	0.035	0.068	0.033
D_EE	0.035	0.052	0.017
S_Supply	0.035	0.095	0.060
D_Demand	0.035	0.063	0.028

Comparing the risk portfolio resource adequacy metrics to baseline shows *how much* worse a portfolio performs if a resource or set of resources is performing at 80% of the expected energy amount for P11. For example, RA would be 2.1 times worse if wind energy output was decreased to 80% with an average increase of about 0.04 MoLOLEV.

Table 23 Comparing the baseline P11 portfolio and P11 risk portfolios MoLOLEV standard deviations

Portfolio	2022 IRP Baseline	Risk	Difference
D_Cust_Solar	0.045	0.060	0.016
D_DR	0.045	0.052	0.008
S_Wind	0.045	0.101	0.057
S_Solar	0.045	0.105	0.061
D_EE	0.045	0.083	0.038
S_Supply	0.045	0.133	0.089
D_Demand	0.045	0.099	0.055

Comparing the standard deviations highlights the variability in RA by portfolio. RA with the reduced energy amount of the risk portfolios is more variable, especially for S_Supply due to the higher maximum MoLOLEV in August 2040.

Other RA metric and comparisons to MoLOLEV are shown in Table 24 and Table 25.

Table 24 All risk statistics

	MoLOLEV		MoEUE		MoLOLH		MoLOLP	
Portfolio	**Mean**	**Std**	**Mean**	**Std**	**Mean**	**Std**	**Mean**	**Std**
D_Cust_Solar	0.042	0.060	12.461	15.094	0.144	0.172	0.007	0.009
D_DR	0.039	0.052	12.970	15.841	0.144	0.174	0.007	0.007
S_Wind	0.074	0.101	21.151	22.133	0.266	0.312	0.012	0.014
S_Solar	0.068	0.105	18.735	21.285	0.245	0.318	0.011	0.015
D_EE	0.052	0.083	13.870	16.418	0.180	0.245	0.008	0.011
S_Supply	0.095	0.133	25.643	26.042	0.326	0.399	0.014	0.018
D_Demand	0.063	0.099	16.510	20.165	0.213	0.307	0.009	0.013

Table 25 Portfolio rankings within each risk statistic

MoLOLEV		MoEUE		MoLOLH		MoLOLP	
Mean	**Std**	**Mean**	**Std**	**Mean**	**Std**	**Mean**	**Std**
D_DR	D_DR	D_Cust_Solar	D_Cust_Solar	D_DR	D_Cust_Solar	D_DR	D_DR
D_Cust_Solar	D_Cust_Solar	D_DR	D_DR	D_Cust_Solar	D_DR	D_Cust_Solar	D_Cust_Solar
D_EE	D_EE	D_EE	D_EE	D_EE	D_EE	D_EE	D_EE
D_Demand	D_Demand	D_Demand	D_Demand	D_Demand	D_Demand	D_Demand	D_Demand
S_Solar	S_Wind	S_Solar	S_Wind	S_Solar	S_Wind	S_Solar	S_Wind
S_Wind	S_Solar	S_Wind	S_Solar	S_Wind	S_Solar	S_Wind	S_Solar
S_Supply	S_Supply	S_Supply	S_Supply	S_Supply	S_Supply	S_Supply	S_Supply

All four RA metrics are important in understanding the resource adequacy of a portfolio, but City Light has not yet set a standard of what is considered “good” for any but MoLOLEV. Because of this, it is helpful to see the overall picture of RA and how a reduction in energy amount affects each metric.

S_Supply has the worst RA across all metrics, and D_Cust_Solar and D_DR have the best, which is in line with the observations made in Table 24. S_Wind has the second largest means and S_Solar has the second largest standard deviations (aka variability), showing that reducing wind has a more balanced effect on RA whereas supply solar has a larger impact in the summer and lower in the winter.

Table 26 All statistics showing the difference between the baseline P11 portfolio and P11 risk portfolios

	MoLOLEV		MoEUE		MoLOLH		MoLOLP	
Portfolio	**Mean**	**Std**	**Mean**	**Std**	**Mean**	**Std**	**Mean**	**Std**
D_Cust_Solar	0.007	0.016	0.779	1.099	0.013	0.021	0.001	0.002
D_DR	0.004	0.008	1.288	1.846	0.012	0.023	0.000	0.000
S_Wind	0.039	0.057	9.469	8.138	0.134	0.161	0.005	0.007
S_Solar	0.033	0.061	7.053	7.289	0.113	0.167	0.004	0.007
D_EE	0.017	0.038	2.188	2.423	0.049	0.094	0.002	0.004
S_Supply	0.060	0.089	13.962	12.047	0.195	0.248	0.007	0.011
D_Demand	0.028	0.055	4.828	6.169	0.082	0.156	0.003	0.006

Table 27 Portfolio rankings within each statistic

MoLOLEV		MoEUE		MoLOLH		MoLOLP	
Mean	**Std**	**Mean**	**Std**	**Mean**	**Std**	**Mean**	**Std**
D_DR	D_DR	D_Cust_Solar	D_Cust_Solar	D_DR	D_Cust_Solar	D_DR	D_DR
D_Cust_Solar	D_Cust_Solar	D_DR	D_DR	D_Cust_Solar	D_DR	D_Cust_Solar	D_Cust_Solar
D_EE	D_EE	D_EE	D_EE	D_EE	D_EE	D_EE	D_EE
D_Demand	D_Demand	D_Demand	D_Demand	D_Demand	D_Demand	D_Demand	D_Demand
S_Solar	S_Wind	S_Solar	S_Wind	S_Solar	S_Wind	S_Solar	S_Wind
S_Wind	S_Solar	S_Wind	S_Solar	S_Wind	S_Solar	S_Wind	S_Solar
S_Supply	S_Supply	S_Supply	S_Supply	S_Supply	S_Supply	S_Supply	S_Supply

Table 26 and Table 27 look at the difference between the statistics with and without an energy amount reduction. The rankings are the same as in Table 27, as the same baseline is used for all portfolios.

Conclusion

These risk runs help City Light assess the potential risk of having less resources than planned. It shows which resources would have a more significant impact in achieving the desired City Light RA metric.

- S_Supply shows that the worst-case scenario is *all* supply-side resources outputting less energy than expected or being unable to get that energy to City Light's customers. This is obviously unlikely, but this analysis does highlight the areas where City Light relies more on supply-side resources.
- S_Wind has the second worst mean RA metric values, showing that P11 relies a lot on the wind power that makes up the bulk of the portfolio.
- S_Solar has more variability in RA, likely due to the inherent variability solar energy has between the summer and winter seasons even without a reduction and the timing of the RA needs under the 2022 IRP Baseline.
- Although City Light is not currently summer-peaking, the risk with the 2022 IRP Baseline load is in the summer (August 2040), with S_Supply, S_Wind, S_Solar, D_Demand, and D_EE not being able to completely meet City Light's RA metric of MoLOLEV of 0.2. In the next IRP, this knowledge will need to be combined with the winter-peaking nature of electrification and the increased summer loads induced by climate change to make sure that City Light is on path to deal with these uncertainties.

Final Thoughts

Based on the assessments above, City Light offers the following observations:

1. City Light should look at a scenario that combines both climate change and electrification. Such scenarios are likely to introduce significant additional RA risk to system planning efforts.
2. Climate change scenarios indicate the biggest RA needs are in the summer.
3. Electrification's biggest RA needs are in the winter; City Light needs to explore future resources that have more energy production and flexibility in the winter (electrification needs are more variable according to the results).
4. The MoLOLEV RA metric can be misleading, as shown in the climate change appendix. City Light should look at incorporating more RA metrics in future work and it should define acceptable thresholds for other RA metrics.
5. City Light should explore the potential of EE and DR under their respective load scenarios. The 2022 IRP Baseline load scenario was used for both shapes and energy potentials in the climate change and electrification scenarios; however, more EE and DR potentials may exist under those loads.
6. Demand Response is a resource that helps reducing the need of both climate change and electrification scenarios, as the top performing portfolios P6, P7, and P11 performed the best in all scenarios overall.

7. City Light should continue to study EE, DR, and behind the meter options given that it is likely that there isn't enough supply side transmission to meet future climate change and electrification futures.

References

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