MEMORANDUM

TO: UTILITIES ADVISORY COMMISSION
FROM: UTILITIES DEPARTMENT
DATE: June 6, 2018
SUBJECT: Long-term Electric Portfolio Analysis Results and Options for Rebalancing Portfolio in the Next Five to Ten Years

REQUEST
Staff seeks UAC feedback on: (a) the Electric Integrated Resource Plan (EIRP) Objective and Strategies (Attachment A), which are intended to guide future analysis and decisions related to the electric supply portfolio over the next five years, and (b) preliminary findings from a long-term electric portfolio planning analysis, which is primarily intended to inform the decision on the renewal of the Western Base Resource contract after the current contract expires in 2024. No action is required at this time.

EXECUTIVE SUMMARY
Palo Alto regularly engages in long-term planning efforts related to its electric supply portfolio – previously under the auspices of the Long-term Electric Acquisition Plan (LEAP) and in the future under the EIRP\(^1\), which the City is required to complete every five years (SB 350). The current EIRP, which must be approved by Council by January 2019, has a planning period of 2018 through 2030. In this period, the City has several wind and landfill gas (LFG) contracts that are scheduled to expire, but the major decision point will be around the Western hydro contract, which will expire at the end of 2024. Palo Alto will have the option, in 2024, of extending that contract – which provides nearly 40% of the City’s supply resources in an average year – for an additional 30-year period. This report presents portfolio analysis results that are an early attempt to inform that decision, and also lays out a timeline and next steps for making the ultimate contract renewal decision in 2024.

The key findings from the analysis are as follows:

a) The Western hydro resource continues to be a valuable component of the City’s electric portfolio, but due to the heavy reliance of the portfolio on one resource and the high degree of cost and output uncertainty related to it, it is worth examining the merits of scaling down the City’s share of this resource;

b) Opportunities exist to further explore rebalancing the electric portfolio to better match the community’s seasonal and hourly electricity demand profile and to reduce reliance on the non-renewable resources from the California Independent System Operator

\(^1\) Staff will hereafter discontinue using the term LEAP and in the future use the term EIRP when seeking long-term electric portfolio plan approvals from the Council.
(CAISO) electric grid. Rebalancing opportunities include replacing an expiring in-state wind contract with baseload generation, such as landfill or geothermal resources, or with out-of-state wind, or by laying off a solar photovoltaic contract or investing in energy storage assets at the solar project sites;

c) Even though the electric portfolio is 100% carbon neutral on an annual basis, calculating its emissions on an hourly basis could yield a significant increase in net emissions, depending on the emissions profile of the larger electric grid. Rebalancing the portfolio to reduce this reliance on the “brown” grid may be worth further examination, knowing that such rebalancing will increase the expected total cost of the portfolio; and

d) Given the high level of adoption of distributed energy resources (DERs) such as electric vehicles, solar photovoltaics, and electrification technologies such as heat pump water and space heaters, ensure the electric supply portfolio can effectively respond to market and technology uncertainties and opportunities and meet the Palo Alto community’s long-term objective of receiving safe, reliable, environmentally sustainable and cost-effective services.

While this analysis has been informative and an important first step, staff will carry out further analysis to inform the decision regarding the City’s level of participation under a new contract for the Western hydro resource closer to the contract decision date in 2024.

This report provides the preliminary electric portfolio analysis and findings, along with the proposed EIRP Objective and Strategies to guide future analysis and decisions. Staff expects to return to the UAC in August/September with the following for discussion and/or approval: (1) the EIRP Objective and Strategies, (2) a work plan and timelines for follow-up analysis focused on the Western contract decision and portfolio rebalancing initiatives, and (3) regulatory documents related to the EIRP that are required to be filed with the state by January 2019.

BACKGROUND

Integrated resource planning (IRP) traditionally is used to develop a plan for meeting forecasted peak and overall energy demand through a combination of supply-side resources (i.e. traditional generators) and demand-side resources (e.g. energy efficiency and demand response programs) over a specified future period. A comprehensive decision analysis modeling tool is used to evaluate costs, benefits and uncertainties related to the various alternatives for meeting energy demands, with the objective of identifying the least-cost, best-fit solutions.

The last time the City completed an IRP analysis was in 2012, when the City’s updated Long-term Electric Acquisition Plan (LEAP) was approved by Council on April 16, 2012 ([Staff Report 2710, Resolution 9241](https://example.com/)). A few years later, Senate Bill 350 (SB 350) was signed into law, and it includes a requirement that publicly-owned utilities (POUs) serving loads greater than 700,000

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2 These market and technology uncertainties and opportunities include: a changing net load profile, greater load uncertainty (both upward and downward, with the latter potentially leading to stranded asset costs), renewable integration issues, new regulatory requirements, and greater availability of flexible loads to facilitate renewables integration and enhance grid operation.
megawatt-hours per year, such as Palo Alto, develop and adopt an IRP and submit it to the California Energy Commission (CEC) by January 2019 and every five years thereafter.\(^3\)

The EIRP planning period is from 2018 through 2030. Through 2028, the City has sufficient renewable power contracts to supply over 50% of its needs. The first of the City’s long-term renewables contracts—for wind power—expires at the end of 2021 and the other wind contract and all five landfill-gas-to energy contracts expire in the late 2020s or early 2030s, while the six solar contracts extend beyond 2040. The City’s contract for the Western hydroelectric resource, which supplies nearly 40% of the City’s electricity needs in a normal hydro year, expires at the end of 2024. A major consideration for the EIRP is whether to renew the contract with Western (and if so, at what participation level) or seek other carbon neutral power supplies.\(^4\)

As part of the 2012 LEAP update, the City Council approved a set of electric portfolio decision-making Objectives and Strategies. At the outset of the current EIRP development process, staff developed an updated Objective and Strategies (Attachment A). The current version, which aligns with the Utilities 2018 Strategic Plan, is very similar to the ones adopted in 2012, with the new Objective and Strategies placing greater emphasis on managing uncertainty related to resource availability and costs, regulatory uncertainty, and the increased penetration of DERs.

The SB 350 mandate to submit an EIRP to the CEC by January 2019 and the need for Council to select a participation level in the renewed Western contract by April 2019 prompted staff to re-evaluate Palo Alto’s long term electric supply portfolio. This report presents a draft set of EIRP Objectives and Strategies, which served as a strategic guide for the portfolio analysis, and which will help guide broader policy decisions related to the electric portfolio in the 2020 to 2030 planning horizon. This document, and an accompanying work plan, will be discussed at greater length in a separate report to the UAC in August. Secondly, this report outlines the aforementioned portfolio analysis results and key findings—which will drive further analysis and inform Council decision making as it approves the EIRP and considers the renewal of the Western hydro contract.

DISCUSSION

In September 2017, staff presented a report and discussion to the UAC outlining the upcoming Western hydro contract decision and a plan for conducting an analysis of the electric portfolio, including a set of potential post-2024 portfolio combinations that would be examined. In that

\(^3\) The Clean Energy and Pollution Reduction Act of 2015 also raised the state’s renewable portfolio standard (RPS) to 50% by 2030 and required a doubling of energy efficiency savings by 2030. The primary objective of the IRP requirement in SB 350 is to ensure that the state’s large POUs are on track to reduce their greenhouse gas emissions, helping the state meet its overall target of reducing GHG emissions to 40% below 1990 levels by 2030.

\(^4\) Based on the current milestone schedule presented by the Western Area Power Administration (WAPA) related to the post-2024 contract extension process, staff’s understanding is that the City must execute the new contract, accepting the updated project allocation, by April 2020. However, according to WAPA there will be a “one-time contract reduction/termination provision” available to customers who execute the new contract in July 2024. https://www.wapa.gov/regions/SN/PowerMarketing/Documents/2025/2025-milestone-schedule.pdf
staff presented a framework for the planned portfolio analysis and discussed a set of key metrics against which the modeled portfolios would be evaluated, including:

- the ability to meet community-wide GHG emission reduction targets;
- cost and rate impacts;
- cost variability and long-term uncertainty;
- portfolio diversity by resource type, location, term and supplier;
- impact on local resiliency;
- level of reliance on fossil fuel resources for balancing load and supply;
- stranded asset risk; and
- ease of management under various conditions.

These key metrics were selected on the basis of their ability to determine how well a given portfolio satisfies the City’s overall planning objectives with respect to its electric supplies. Those objectives can be summarized as: a desire to provide safe, reliable, environmentally sustainable and cost-effective electric resources and services to all customers. More details on these planning objectives, and the strategies staff utilizes in pursuit of them, are provided in Attachment A.

A. Current Portfolio Profile and Characteristics

The City’s current electric supply portfolio comprises the following major types of resources:

- Federal hydro (Western contract);
- Owned hydro (Calaveras);
- Long-term, in-state, RPS-eligible power purchase agreements (PPAs), which include solar, wind, and landfill-gas resources;
- Distributed energy resources (DERs), including energy efficiency and rooftop solar; and
- Market power purchases, matched with RECs, for monthly/hourly portfolio balancing.

For calendar year 2020, the projected contribution of each of these five resource types to the City’s overall supply portfolio is represented in Figure 1 below. Additional details about all of these portfolio resources are presented in Attachment B.
On a shorter timescale, however, the portfolio looks significantly different. Shown below are two daily/hourly load and resource balance graphs from an average hydro year – for a typical day in January (Figure 2), when hydro and solar output are both minimal, and for a typical day in July (Figure 3), when hydro and solar are both in abundance.5

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5 These graphs include only the City’s hydro and long-term PPA resources; not shown are DERs (which reduce the City’s load) and market purchases (which make up the differences, positive or negative, between the City’s total purchases and its load).
Figure 2: Daily Load and Hydro/PPA Supplies for a Typical January Day in an Average Year

Figure 3: Daily Load and Hydro/PPA Supplies for a Typical July Day in an Average Year
Note that as hydro is a dispatchable resource, it is currently dispatched to optimize the financial value of the resource, rather than to balance the City’s load and supply resources. This explains the odd shape of the July supply profile: market prices tend to peak in the evening hours (when solar output is declining and evening loads are increasing), so the bulk of the hydro generation is concentrated in this period. However, this dispatch pattern could be modified if the City wanted to reduce its reliance on the greater electric grid; for example, the hydro resources could be scheduled like “baseload” resources, which have a steady output level across the day. (However, this output level would still vary seasonally, based on snowpack levels, runoff conditions, and streamflow requirements.) Figure 4 presents a daily load and resource balance graph for a typical July day where the hydro resources are dispatched in a baseload/load-following manner.

**Figure 4: Load and Resources for a Typical July Day with Hydro as a Baseload Resource**

However, it should be noted that although dispatching the City’s hydro resources in this manner will likely result in lower net GHG emissions, it would likely result in higher cost to the electric rate payer – preliminarily estimated at a retail rate increase of 1 to 2 percent, or an annual supply cost increase of $1 to $2 M.
B. Options to Rebalance Portfolio

As noted in the September 2017 report to the UAC, staff evaluated a very large number of potential new supply-side and demand-side resources in the portfolio analysis. However, as the analysis progressed, due to reasons of feasibility/availability and cost/uncertainty, staff narrowed the focus of the analysis to the following resources:

- A renewed Western hydro contract,
- In-state solar,
- Out-of-state wind,
- Geothermal,
- Local (Palo Alto) solar, and
- Market purchases matched with renewable energy certificates (RECs).

The Western hydro resource and in-state solar resource characteristics are well understood, given the large role they each play in the current portfolio. Western is a relatively low-cost, flexible resource – at least in average years – but it features a large amount of seasonal variability, as well as year-to-year uncertainty around its cost and level of output. In addition, there are several major issues currently pending that have the potential to significantly impact the cost and/or operation of the resource.\(^6\) Solar also involves a great deal of seasonal variability and contributes towards the seasonal imbalance of the supply portfolio, but with far less uncertainty around its cost or annual output amount. And while its costs have decreased dramatically in recent years, the huge volume of recent capacity additions – which have been concentrated in areas with the best solar potential – have driven down the market value of this energy at least as much, leading to a sharp increase in negative market prices and curtailments. The rise of solar generation in the state has also led to the Duck Curve phenomenon\(^7\), which has in turn resulted in new regulatory requirements for each load-serving entity (LSE) to procure sufficient flexible generation capacity to maintain transmission grid reliability.

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\(^6\) For example: The State Water Resources Control Board has several proceedings underway that may have very significant impacts on Western operations, including the consideration of an “unimpaired flow” criteria as part of its Bay Delta Plan that could result in significantly less generation from Western, particularly in the summer months. There are also long-term risks associated with an increase in “Aid to Irrigation” payments that Power customers may be required to make to Water customers, litigation related to the Central Valley Project Improvement Act (CVPIA) Restoration Fund payments that Power customers make, potential cost impacts to Power customers related to the “Twin Tunnels” project, and the impacts of climate change on the resource. Staff hopes that many of these uncertainties will be better understood by 2024; however it is likely that a number of them will remain unresolved. These risks must be more closely examined before making a final contract commitment in 2024.

\(^7\) The Duck Curve refers to a graph created by CAISO showing the impact of the increasing adoption of solar PV on CAISO’s net load (i.e., total load less generation from variable energy resources like wind and solar). Over time, as more solar generation came online, the CAISO net load curve went from having a slight mid-day peak to having a deep mid-day trough, bracketed by a steep downward ramp in the morning, as solar plants began generating, and an even steeper upward ramp in the evening, as the sun goes down. For more information, see: [https://www.caiso.com/documents/flexibleresourceshelprenewables_fastfacts.pdf](https://www.caiso.com/documents/flexibleresourceshelprenewables_fastfacts.pdf).
Out-of-state wind resources – e.g., from the Pacific Northwest or New Mexico – have also become very low-cost in recent years, in some cases even lower priced than solar.\(^8\) Wind resources from these areas typically have a generation profile that is a good fit for the City’s portfolio, producing somewhat more energy in the fall and winter months than in the spring and summer months. However, the cost of obtaining transmission access for them into the state significantly raises their total cost.\(^9\)

Geothermal resources have also experienced a price decline in recent years, although they are still less valuable compared with solar or out-of-state wind. New binary cycle geothermal technology also produces no GHG emissions and can be more flexibly dispatched compared to prior generations of geothermal technologies. This technology bears further consideration in the coming years as the City considers options to rebalance the portfolio.

Local solar is the only local supply resource considered in the portfolio analysis. While it would have a higher value than solar located in the central San Joaquin Valley\(^10\) it is unlikely to be available in sufficient quantities to make a significant contribution to the City’s overall electric supply needs. The cost of such local systems would also be relatively high. For example, under the Palo Alto CLEAN program, even with a contract price of 16.5 cents/kWh, the program existed for several years before finally securing about 3 MW of participating capacity within the last two years. And the cost of solar energy from a 500 kW project at the Palo Alto golf course was estimated at 10 to 14 cents/kWh in 2017, which is more costly compared to other resource options, even with the greater value of local generation.

Finally, market energy purchases combined with unbundled RECs could present an attractive option in the short-term if the City wishes to reduce its Western contract allocation and seek a different low-cost solution. In the long-term, however, many forecasts indicate that as the state’s GHG reduction requirements ratchet up, the cost of carbon allowances will likewise climb, which in turn would raise market power prices and make this option uneconomic. In addition, this approach would perpetuate the City’s reliance on traditional GHG-emitting generators. On the other hand, shorter-term market purchases would provide the City with a great deal of flexibility in terms of contract duration and volume, and lower the risk of stranded energy resources if the electric loads available to be served by the City decline significantly.

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\(^8\) Staff has received numerous proposals for out-of-state wind resources over the past several years, but such resources were found to be uneconomical compared to in-state solar when Palo Alto made long-term commitments for solar resources between 2012 and 2016.

\(^9\) The availability of transmission pathways to bring this generation into CAISO on a reliable basis is also not assured. However, for Pacific Northwest wind resources, the City’s allocation of capacity on the California-Oregon Transmission Project (COTP) could prove very useful. The City laid-off this transmission asset for a 15-year period, but this layoff will end at the end of 2023.

\(^10\) Local solar is currently at least 3 ¢/kWh more valuable than remote solar, given that it would provide enhanced local resiliency, would not be subject to transmission charges, would reduce the City’s resource adequacy capacity requirements, and would have a high locational value, due to its mitigating effect on Bay Area transmission congestion.
Table 1 below summarizes the various resource types that staff considered most closely in its portfolio analysis and their relative merits. The key indicators used for comparing the different portfolio options are:

- **Value**: The net value of a resource; the projected revenue from selling the resource’s energy into the CAISO market less the resource’s bi-lateral contract cost;
- **Portfolio Fit**: Lower reliance on the grid for hourly load balancing;
- **Diversification**: Geographic and resource diversity;
- **Term Flexibility**: Flexibility in length of contract and termination provisions; and
- **Cost Certainty**: Degree of certainty of future resource costs.

Table 1: Relative Merits of Candidate Resources Considered to Rebalance Supply Portfolio

*Ratings reflect relative changes from current portfolio of resources*

<table>
<thead>
<tr>
<th>Post-2024 Resource Options</th>
<th>Value</th>
<th>Portfolio Fit</th>
<th>Diversification</th>
<th>Term Flexibility</th>
<th>Cost Certainty</th>
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<td>Federal Hydro (WAPA)</td>
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<td>Market Purchases &amp; RECs</td>
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Legend: High → Medium → Low

C. Portfolio Analysis and Results

The EIRP portfolio analysis involved a combination of scenario-based spreadsheet analysis to test discrete portfolio combinations, and hourly portfolio value optimization using a proprietary CAISO network nodal pricing modeling tool called Gen X. Details of this analysis are included in Attachment C, but the high-level results are described below to inform the discussion of potentially rebalancing the electric portfolio.

Portfolio Expected Net Value

First, as far as the net value of a resource contract for the 2025 to 2030 period, Western has the potential to be a relatively valuable resource, but also has the most uncertainty when it comes to costs, for the reasons described above. The expected net value of Western and several potential new contracts, as determined by the scenario-based spreadsheet analysis, is shown in Figure 5. The net value of each resource is calculated based on its energy values (from each
resource’s LMP forecast), along with the ancillary services value provided by Western, the value of the RECs generated by the renewable resources, and each resource’s RA capacity. Note that the expected net value of some resources is negative (less valuable than projected market value), due to the fact that the cost of all of the renewable resources includes the cost of renewable attributes in addition to energy, and because a primary goal of a long-term agreement such as a PPA is to hedge and manage exposure to future price volatility.

**Figure 5: Expected Net Value of New Resources and Western Relative to Market Value**

*Very High Cost Uncertainty around Western*

One of the primary messages of Figure 5 is that there is a tremendous amount of uncertainty around the net value of Western, as indicated by the large uncertainty bars featured on that data series. It should be noted that the uncertainty shown in Figure 5 is illustrative only, and based on staff’s best estimate of the potential range of future Western contract costs. It should also be noted that this uncertainty is heavily biased toward the negative direction: there is limited “upside” uncertainty while there is a great deal of “downside” uncertainty, largely related to pending environmental regulatory issues.

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11 Figure C-6 does not include market price uncertainty or hydrological uncertainty; the uncertainty range shown for Western represents purely regulatory and litigation-related cost uncertainty.

12 See Attachment D for further discussion on the sources and potential magnitude of this uncertainty.
Portfolio Fit
Another key indicator is hourly portfolio fit, which will determine how reliant the portfolio is on grid power (and, as a result, how exposed it is to market prices). Figure 6 average hourly generation profiles for each month (one average day per month is shown) for Western and other potential new resources relative to the City’s average load. As shown in Figures 2, 3 and 4 in this report, total resource supplies from long-term contracts exceed the City’s load in the spring and summer months, while the opposite is true during the fall and winter months. Thus Figure 6 indicates that out-of-state wind, which produces more energy in the fall and winter months, would be a good complement to the City’s existing portfolio. In-state wind (in the Solano hills) and solar, on the other hand, exacerbate the City’s portfolio fit problem, as they produce more energy in the spring and summer months.

Figure 6: Average Hourly Load and Generation Profiles for Each Month for Western and Potential New Resources (Normalized to Average Hourly Load)

* New Mexico Wind Resource Profile Complements Palo Alto Portfolio *

Portfolio Cost Uncertainty and Management
The cost uncertainty of the electric supply portfolio in the short-term is primarily driven by the water available for hydroelectric production, and is estimated at $10 to $15 million per year at prevailing market prices. Palo Alto is well positioned to manage this cost uncertainty through
the hydro rate adjustment mechanism\textsuperscript{13} and by maintaining sufficient cash reserves. The cost uncertainty related to seasonally balancing the portfolio\textsuperscript{14} is minimal since market price variability between seasons is highly correlated and because these seasonal buy-sell transactions are undertaken at the same time.

As noted above, in the long-term, there are a number of issues that could dramatically affect the value of the Western resource in the coming years. There are also proceedings underway to investigate market restructuring to deal with issues related to the integration of variable renewable resources, such as over-generation, very steep evening ramp periods, and the appropriate valuation of dispatchable capacity. Volatility in market prices, as the CAISO and the CEC determine how to send price signals to ensure a reliable grid, could leave a seasonally unbalanced portfolio such as the current portfolio exposed. Increases in transmission charges could also make remote resources compare less favorably to local resources and demand side management in the future.

Attachment D outlines these and other risk factors, the impact of these long-term risks, and ways that the City and its joint action agency partners are working towards managing these cost uncertainties. A large focus of staff efforts in the next five years will be to better understand the long-term economics of the Western resource and mitigate the risks associated with it through flexible contractual terms – for example, the ability for Palo Alto to reduce its share of the project output if the economics of this resource diminish over the 30-year duration of the next contract.

\section*{D. Impact of GHG Emissions Accounting Methodology}

Palo Alto’s current GHG emissions accounting methodology, which involves tallying the net annual load and generation amounts from different resource types, was adopted from protocols established by The Climate Registry (TCR), which are widely accepted and used across the electricity industry. However, a potentially more accurate methodology for accounting for the portfolio’s GHG emissions would be to track the City’s net portfolio position (surplus or deficit) \textit{by hour}, and apply the statewide or CAISO grid-wide hourly emissions intensity factors to these values. Given that proceedings are currently underway at the California Air Resources Board (CARB), the CEC, and the California Public Utilities Commission (CPUC) regarding the methodology for accounting for the electricity sector’s GHG emissions, staff recommends waiting to see the results of these proceedings before implementing any changes to the City’s current accounting methodology.\textsuperscript{15} But for informational purposes, staff has evaluated the effects of switching to the hourly emissions accounting methodology on the current portfolio.

\textsuperscript{13} For additional detail on the hydro rate adjustment mechanism, please see Staff Report ID 8962 (March 2018): https://www.cityofpaloalto.org/civicax/filebank/documents/63851.

\textsuperscript{14} Revenues received from the sale of surplus energy during the spring and summer periods are utilized to purchase electricity needs for the fall and winter periods.

\textsuperscript{15} For example, there is some interest in requiring hourly emissions accounting which does not include the carbon displaced when a load serving entity has surplus resources in excess of its load; under that “Clean Net Short” accounting the City would be considered to have annual emissions in 2018 of approximately 68,000 metric tons of CO2, which is equivalent to about 15\% of Palo Alto’s community-wide emissions estimate for 2017. (The California
In this hourly emissions accounting methodology the hourly average emissions of the California electricity mix are considered to be “displaced” when the City’s carbon free resources exceed the City’s load (when the portfolio is in surplus), and are considered to be “emitted” when load exceeds resource supply (when the portfolio is in deficit). The concept of “displacement” stems from the fact that the total energy generated on the CAISO grid must always equal the total energy consumed due to the physics of the system. As a result, if Palo Alto generates a surplus, it means that another power plant must be turned off. Since Palo Alto’s surplus generation is carbon-free, and in most hours the power plant being turned off is a gas-fired plant, on balance, the CAISO grid emits less carbon because of Palo Alto’s surpluses.16

Initial analysis17 suggests that the City displaces less carbon during its surplus hours than the amount it emits during its deficit hours – with the portfolio on balance responsible for about 4,000 to 6,000 metric tons of net carbon dioxide emissions per year (mTCO₂/yr).18 This is because the City’s surplus hours tend to occur during the spring and summer months, when hydro and solar generation are in abundance across the state, and its deficit hours tend to occur in the fall and winter months, when overall there is more gas-fired generation supplying the statewide electricity mix. This effect is evident in Figure 7, which shows the projected 2018 statewide hourly electricity emissions profile for each quarter of the calendar year.

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Public Utilities Commission (CPUC) has proposed, in Rulemaking 16-02-007, that the Clean Net Short GHG accounting methodology be used by CPUC-jurisdictional load-serving entities in their IRP filings. See: [http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M212/K646/212646820.PDF](http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M212/K646/212646820.PDF). Staff is monitoring the regulatory developments closely and will consider these results in analyses to come.

16 Staff is able to estimate the emissions of the displaced plant using hourly grid-average GHG emissions intensity factors provided by the California Air Resources Board. See Table 7-2 of the Low Carbon Fuel Standard preliminary draft regulation: [https://www.arb.ca.gov/regact/2018/lcfs18/appa.pdf](https://www.arb.ca.gov/regact/2018/lcfs18/appa.pdf).

17 Please see Attachment C for additional details on this analysis.

18 Instead of using hourly average grid emissions, another way to estimate the emissions displaced or emitted is the marginal hourly grid emissions rate. This would be the emissions rate of the marginal plant that would be shut off or turned on depending on Palo Alto’s portfolio surplus or deficit. This data is not readily available to staff’s knowledge at this time, and using the hourly average grid emissions rates is the best estimation method available.
However, if one considers only the hours in which the City relies on the grid to supply energy, and ignores the “displaced” emissions resulting from the City’s surplus renewable energy, the carbon associated with this energy is estimated at 60,000 to 80,000 metric tons per year. This is equivalent to about 14% to 18% of the community-wide emissions estimate for 2017.\(^{19}\) As the state continues to refine and update the marginal and average hourly emission factors for the electricity grid, staff will utilize these estimates to examine ways to further lower the community’s carbon footprint in the most economic fashion.

### E. Strategies and Next Steps to Rebalance the Portfolio

As there is so much uncertainty regarding the Western resource, and because the decision is such a consequential one, it merits a follow-up analysis closer to the contract renewal date, which is currently scheduled for mid-2020. Even after that, the City likely has until July 2024 to make a decision to reduce or reject its allocated share of the future Western contract, which is expected to be approximately as large as its current share. The additional analysis regarding this decision should include:

1. An examination of the City’s net load forecast and associated uncertainties, in line with the Draft DER Plan discussed with the UAC in November 2017, with particular emphasis on how it may be affected by customer adoption of DERs (EVs, Demand Response, ...

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Energy Efficiency, Solar PV, storage, and building electrification) in order to avoid stranding assets.

2. An update and extension of the current portfolio analysis, including updates to the hourly LMP forecasts and the costs, assumptions, and uncertainties associated with all resource options.

3. Analysis of the projected costs, output, and flexibility of the renewed Western contract, to reduce the amount of outstanding uncertainty around this resource.

4. Evaluation of specific carbon-free resource options, which may be best accomplished by issuing a Request for Proposals (RFP) in order to get up-to-date, actionable price data. This RFP could look at acquiring new resources to replace the Western contract after 2024, as well as swapping one or more solar resources for baseload or wind resources, in order to improve the overall fit of the supply portfolio to the City’s net load.

5. Evaluation of the City’s share of the California-Oregon Transmission Project (COTP): while the City has temporarily assigned its share of COTP to others, this lay-off will end in 2024. Staff will investigate how this asset can best be utilized given future market conditions, including the cost and availability of carbon-free resources in the Northwest.

6. Advocating for flexible contractual provisions in the new Western contract, and examining the legal and economic merits and risks associated with committing to the Western resource for 30 more years.

Aside from the Western contract decision, staff will continue its activities in pursuit of lowering the overall cost to serve load. These include continuing to optimize the use of the City’s Calaveras resource, evaluation of the benefits of the NCPA pool and/or the procurement of alternative scheduling services for its renewable resources.

**NEXT STEPS**
Staff is seeking feedback from the UAC on the analysis findings presented in this report and next steps. Input is also sought on the proposed EIRP Objective and Strategies (Attachment A) to guide electric portfolio decisions for the next five years.

Staff will carefully consider the UAC’s input on the portfolio analysis performed to date, the proposed Western contract analysis work plan, and the proposed EIRP Objective and Strategies. Staff anticipates returning to the UAC in August to discuss the proposed EIRP Objective and Strategies and work plan for the next five years, and then again in September to discuss the final EIRP report, before sharing these documents with the Council for their input as well.

**RESOURCE IMPACT**
Staff has access to a wide pool of resources through NCPA to more closely analyze the Western resource and contractual options. Given the complexity and importance of the decision on the 2025 Western contract, staff may seek external consulting and legal assistance, to augment NCPA’s resources and services, and those of the City Attorney’s office. The cost of such external resources may amount to $100,000 to $200,000 over the next few years.

Under its existing staffing resources, staff expects to devote approximately 0.75 to 1.5 FTE in the coming years to pursuing strategies to rebalance the electric portfolio to meet the challenges of the coming decades.
POLICY IMPLICATIONS
The EIRP Objective and Strategies is in line with the Utilities Strategic Plan mission and strategic direction. Specifically, the EIRP itself was contemplated under Strategy 4, Action 5, of the Financial Efficiency and Resource Optimization Priority of the Utilities 2018 Strategic Plan. The EIRP is also in line with the Sustainability and Climate Action Plan goals of continuing to lower the carbon footprint of the community.

ENVIRONMENTAL REVIEW
The Utilities Advisory Commission’s discussion of the EIRP work plan does not meet the definition of a project under Public Resources Code 21065 and therefore California Environmental Quality Act (CEQA) review is not required.

ATTACHMENTS
A. Proposed Electric Integrated Resource Plan Objective and Strategies
B. Details of Current Electric Supply Portfolio Resources
C. Long-term Electric Supply Portfolio Analysis Framework, Results, and Findings
D. Long-term Electric Supply Portfolio Cost Uncertainties and Mitigation Strategies

PREPARED BY: LENA PERKINS, Resource Planner
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General Manager of Utilities
Electric Integrated Resource Plan (EIRP)
Objective and Strategies

EIRP Objective
To provide safe, reliable, environmentally sustainable and cost-effective electric resources and services to all customers.

EIRP Strategies
1. **Pursue an Optimal Mix of Supply-side and Demand-side Resources:** When procuring to meet demand, pursue an optimal mix of resources that meets the EIRP Objective, with cost-effective energy efficiency, distributed generation, and demand-side resources as preferred resources. Consider portfolio fit and resource uncertainties when evaluating cost-effectiveness.
2. **Maintain a Carbon Neutral Supply:** Maintain a carbon neutral electric supply portfolio to meet the community's greenhouse gas (GHG) emission reduction goals.
3. **Actively Manage Portfolio Supply Cost Uncertainties:** Structure the portfolio or add mitigations to manage short-term risks (e.g. market price risk and hydroelectric variability) and build flexibility into the portfolio to address long-term risks (e.g. resource availability, customer load profile changes, and regulatory uncertainty) through diversification of suppliers, contract terms, and resource types.
4. **Manage Electric Portfolio to Ensure Lowest Possible Ratepayer Bills:** Pursue resources in a least-cost, best-fit approach in an effort to ensure ratepayer bills remain as low as possible, while adhering to Council-adopted rate and financial objectives and guidelines.
5. **Partner with External Agencies to Pursue Synergistic Opportunities:** Engage and partner with external agencies to maximize resource value and optimize operations.
6. **Manage Customer Load Profile and Load Uncertainty:** Maintain electric supply resource flexibility in anticipation of potential changes in customer loads due to distributed energy resources, efficiency, electrification, or for other reasons.
7. **Ensure Transmission and Distribution System Reliability and Local Resiliency:** Work with the transmission system operator to receive reliable service in a cost-effective manner. Maintain distribution system reliability and support local programs that enhance community resiliency.
8. **Comply with State and Federal Laws and Regulations:** Ensure compliance with all statutory and regulatory requirements for energy, capacity, reserves, GHG emissions, distributed energy resources, efficiency goals, resource planning, and related initiatives.
Details of Current Electric Supply Portfolio Resources

Palo Alto’s electric supply portfolio has become, over the past 15 years, a diverse mix of hydro, wind, landfill gas, and solar resources. The average energy cost for these resources is about $60/MWh, or 6 ¢/kWh. This energy cost accounts for almost 50% of the average customer retail rate. However, this figure—and the annual cost total ($65 million) shown in Table B-1 below—does not include the cost of transmission, resource adequacy capacity, or the power management services provided by NCPA. If one includes these costs, the average cost to receive energy in Palo Alto would be closer to 8.5 cents/kWh—which represents about 70% of the average customer retail rate.

Table B-1: Palo Alto’s Existing Electric Supply Resources

<table>
<thead>
<tr>
<th>Project</th>
<th>Supplier</th>
<th>Technology</th>
<th>Actual or Estimated Start Date</th>
<th>Contract Expiration Date*</th>
<th>Contract Duration (Years)</th>
<th>Annual Energy (GWh)</th>
<th>Contract Cost ($/MWh)</th>
<th>Annual Cost ($M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Western Base Resource</td>
<td>WAPA</td>
<td>Hydro</td>
<td>Jan. 2005</td>
<td>Dec. 2024</td>
<td>20</td>
<td>364.3 (avg)</td>
<td>$37.55 (avg)</td>
<td>$13.7 (avg)</td>
</tr>
<tr>
<td>Calaveras Project</td>
<td>NCPA</td>
<td>Hydro</td>
<td>Jan. 1990</td>
<td>N/A</td>
<td>N/A</td>
<td>131.7 (avg)</td>
<td>$91.10 (avg)</td>
<td>$12.0 (avg)</td>
</tr>
<tr>
<td>High Winds</td>
<td>Avangrid</td>
<td>Wind</td>
<td>Dec. 2004</td>
<td>Jun. 2028</td>
<td>23.7</td>
<td>42.7</td>
<td>$57.60</td>
<td>$3.24</td>
</tr>
<tr>
<td>Shiloh I</td>
<td>Avangrid</td>
<td>Wind</td>
<td>Jun. 2006</td>
<td>Dec. 2021</td>
<td>15.5</td>
<td>57.3</td>
<td>$64.95</td>
<td>$3.72</td>
</tr>
<tr>
<td>Santa Cruz</td>
<td>Ameresco</td>
<td>Landfill Gas</td>
<td>Feb. 2006</td>
<td>Feb. 2026</td>
<td>20</td>
<td>9.0</td>
<td>$60.98</td>
<td>$0.55</td>
</tr>
<tr>
<td>Ox Mountain</td>
<td>Ameresco</td>
<td>Landfill Gas</td>
<td>Apr. 2009</td>
<td>Mar. 2029</td>
<td>20</td>
<td>42.5</td>
<td>$59.25</td>
<td>$2.53</td>
</tr>
<tr>
<td>Keller Canyon</td>
<td>Ameresco</td>
<td>Landfill Gas</td>
<td>Aug. 2009</td>
<td>Jul. 2029</td>
<td>20</td>
<td>13.8</td>
<td>$71.00</td>
<td>$0.98</td>
</tr>
<tr>
<td>Johnson Canyon</td>
<td>Ameresco</td>
<td>Landfill Gas</td>
<td>May 2013</td>
<td>May 2033</td>
<td>20</td>
<td>9.2</td>
<td>$116.80</td>
<td>$1.08</td>
</tr>
<tr>
<td>San Joaquin</td>
<td>Ameresco</td>
<td>Landfill Gas</td>
<td>Apr. 2014</td>
<td>Apr. 2034</td>
<td>20</td>
<td>27.5</td>
<td>$107.20</td>
<td>$2.95</td>
</tr>
<tr>
<td>EE Kettleman Land</td>
<td>Clēnera</td>
<td>Solar PV</td>
<td>Jul. 2015</td>
<td>Aug. 2040*</td>
<td>25</td>
<td>52.8</td>
<td>$77.00</td>
<td>$4.07</td>
</tr>
<tr>
<td>Hayworth Solar</td>
<td>sPower</td>
<td>Solar PV</td>
<td>Dec. 2015</td>
<td>Dec. 2042*</td>
<td>27</td>
<td>63.1</td>
<td>$68.72</td>
<td>$4.34</td>
</tr>
<tr>
<td>Frontier Solar</td>
<td>Clēnera</td>
<td>Solar PV</td>
<td>Aug. 2016</td>
<td>Aug. 2046</td>
<td>30</td>
<td>52.1</td>
<td>$69.00</td>
<td>$3.59</td>
</tr>
<tr>
<td>Elevation Solar C</td>
<td>sPower</td>
<td>Solar PV</td>
<td>Dec. 2016</td>
<td>Dec. 2041*</td>
<td>25</td>
<td>100.2</td>
<td>$68.77</td>
<td>$6.89</td>
</tr>
<tr>
<td>Western Antelope Blue Sky Ranch B</td>
<td>sPower</td>
<td>Solar PV</td>
<td>Dec. 2016</td>
<td>Dec. 2041*</td>
<td>25</td>
<td>50.1</td>
<td>$73.77</td>
<td>$3.70</td>
</tr>
<tr>
<td><strong>Subtotal – Operating</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1,016.3</td>
<td>$61.56</td>
<td>$62.56</td>
</tr>
<tr>
<td>Wilsona Solar</td>
<td>Hecate</td>
<td>Solar PV</td>
<td>Jun. 2021</td>
<td>May 2046*</td>
<td>25</td>
<td>75.0</td>
<td>$36.76</td>
<td>$2.76</td>
</tr>
<tr>
<td><strong>Subtotal – Under Development</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>75.0</td>
<td>$36.76</td>
<td>$2.76</td>
</tr>
<tr>
<td><strong>Total – All Executed Contracts</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1,091.3</td>
<td>$59.86</td>
<td>$65.32</td>
</tr>
</tbody>
</table>

* All of the solar contracts include extension term options beyond the listed expiration date.
Long-term Electric Supply Portfolio Analysis Framework, Results, and Findings

A. ANALYSIS FRAMEWORK

Modeling Framework & Assumptions
The analysis utilized the publicly available California Independent System Operator (CAISO) security-constrained full network model (FNM) with 6,000+ nodes to project hourly nodal prices\(^1\) over the 2018-2030 analysis period. The analysis focused on 50 nodes and aggregation points of particular interest to Palo Alto.\(^2\)

Consistent with the current CAISO market construct, it was assumed that all generation resources are compensated based on an hourly price specific to the transmission node (PNode) at which they deliver electricity to the grid, and that Palo Alto’s load pays an hourly Northern California Default Load Aggregation Point (PG&E DLAP) price for electricity received from the transmission grid at its Colorado Avenue substation.

The model was then provided input assumptions related to: (a) natural gas prices, (b) statewide annual peak demand and electricity load, (c) statewide generation capacity additions and retirements, (d) carbon allowance prices, and (e) transmission capacity additions. All of these variables were projected out through 2030, and several of the key assumptions are graphically illustrated in Figure C-1 below to show the change in these variables over time relative to their 2018 levels.

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\(^1\) The CAISO full network model nodes consist of almost 2,000 generation nodes, over 200 intertie nodes, and almost 5,000 load nodes; prices were computed for each of the 8760 hours in a year for the 13 years 2018-2030. The full list of nodes can be found at: [http://www.caiso.com/market/Pages/NetworkandResourceModeling/](http://www.caiso.com/market/Pages/NetworkandResourceModeling/).

\(^2\) The nodes for which Palo Alto received price forecasts included all of the City’s existing generation resources, the PG&E DLAP, the NP15 trading hub (a highly liquid trading hub for Northern California, where Palo Alto makes all of its market purchases and sales), and a variety of diverse nodes representing potential future wind, solar, and geothermal resources. To forecast the value of out-of-state resources, Palo Alto also received price forecasts for several “intertie points” – locations where the CAISO grid connects to other balancing areas.
The model was also provided with Palo Alto’s most recent hourly electric load forecast, and an hourly annual electricity generation profile for each generation resource in Palo Alto’s current electric supply portfolio. The model was also given hourly generation profiles for candidate resources for the future, such as out of state wind and geothermal resources. Since the Western and Calaveras hydro resources are energy-limited but are highly flexible to dispatch within a day and across days, these flexible resources were dispatched in more valuable periods based on the model’s nodal price (or locational marginal price, LMP) projections, subject to each resource’s operating constraints. In other words, the model was permitted to dispatch these resources to maximize their value, similar to how the City’s resource schedulers dispatch them today; their generation profiles were not deterministic inputs to the model.

A spreadsheet model was also built to utilize the LMP price output from the FNM to value the resources in the portfolio and resources that may be candidates to rebalance the portfolio. This model included the following components:

1. **Existing portfolio:** The spreadsheet model includes all committed resource profiles and costs, including pre-2025 Western, executed renewable PPAs, and the Distributed Energy Resources (DERs) proposed in the DER plan.

2. **Future resource options:** The resource options included in the model were: various sizes of a post-2024 Western contract, additional DERs, additional local solar (CLEAN), and new renewables. The potential new renewable options included in-
state solar, geothermal, and out-of-state wind. Future resource costs are estimated from available data and information from suppliers. All new resources were assumed to be added to the portfolio in 2025, just as the existing Western contract expires.

3. **Hourly cost/revenue**: The cost of the City's load and the revenue received for contracted generation is calculated using the appropriate hourly nodal price projections.

4. **Carbon-neutral constraint**: All portfolios evaluated were required to be carbon-neutral. If needed for any particular portfolio, Renewable Energy Certificates (RECs) were assumed to be purchased to meet the carbon neutral requirement.

5. **Resource Adequacy**: Requirements for system and local resource adequacy (RA) are projected and met at forecast prices for those needs. RA surpluses are assumed to be sold. Flexible RA needs for new resources are estimated and depend on the resource type (i.e., intermittent resources like wind and solar are assumed to require flexible RA, while baseload resources like geothermal are assumed to not need it).

**Optimization Function**

The optimization of the modeling framework was based on the following:

1. Maximize the value of the resource within the portfolio given the nodal price forecast from the FNM model output – in particular the hydro resources, which can be dispatched based on CAISO hourly market prices.

2. Minimize the net cost to Palo Alto, given that resources get paid the LMP prices through the CAISO market and Palo Alto has to pay the bi-laterally negotiated contract price for the resource. (Note: Palo Alto load pays the hourly PG&E DLAP price, which is an output of the FNM model, but is not included in the optimization function.)

3. Resources were selected and dispatched to meet the City’s annual load projections, and not to match resources to load on an hourly basis.

4. Resource portfolios with the lowest total costs over the 2018-2030 analysis period were then ranked based on the hourly-load resource balance, with portfolios with the least hourly reliance on market purchases and sales ranked higher, based on having a better portfolio fit.

**B. MODEL OUTPUT RESULTS**

As described above, the first output of the FNM was a set of hourly nodal price forecasts covering the 13-year period from 2018 through 2030. Figure C-2 below presents the monthly average prices over the entire 13-year period for two nodes of particular interest to Palo Alto: the PG&E DLAP and the NP15 trading hub. This shows that market prices are expected to remain low – between $30 and $40 per Megawatt-hour (MWh) – for the next several years, before climbing to over $70 per MWh. The spread between the high and low prices in a given year is also expected to expand quite a bit. And lastly, the PG&E DLAP price – the price paid by the City’s load – is consistently a bit higher than the NP15 trading hub price.
Figure C-3 below is similar to Figure C-2 – it presents price forecasts for the PG&E DLAP and the NP15 trading hub – but in this case it presents the hourly prices for an average day of each month in a single year (2025). This chart indicates that the effects of the Duck Curve – where prices are at their lowest in the spring, when system-wide loads are very low and solar generation is growing, and where there is a mid-afternoon price dip each day when solar generation is at its peak – are still expected to be present in 2025.
Figures C-4 and C-5 below present the differences (spreads) between the nodal prices of a variety of generation resources (including all of the City’s existing resources and some potential future ones) and the PG&E DLAP price. Figure C-4 shows average monthly values over the 13-year forecast period, while Figure C-5 shows this information for an average 24-hour period each month of a particular year (2025).

This information shows how valuable each resource type’s energy is, as well as how effective of a hedge each resource type is against the City’s load costs. (This does not, however, illustrate the “net value” of a resource, because it does not take into account the bilateral contract cost of each resource, or the value of the RECs or RA capacity associated with a resource.) An ideal resource will have relatively valuable energy (i.e., a positive spread versus the PG&E DLAP price) and a relatively consistent spread versus the PG&E DLAP.

Figures C-4 and C-5 both indicate that the nodal price value of the City’s landfill gas (“LFG”) resources is consistently higher than the PG&E DLAP. This is probably due to the fact that the City’s five LFG projects are located in and around the Bay Area, which tends to experience a large amount of electrical congestion and thus has high nodal prices. The other resource types tend to have negative price spreads compared to the PG&E DLAP — particularly the statewide geothermal price (and, to a lesser extent, the City’s solar projects). The nodal price of northern California geothermal (from the Geysers area) is projected to be similar to the City’s wind and
Western hydro resources, but the statewide geothermal nodal price projection is weighed down by an extremely low projected value for a southern California geothermal resource.

Figure C-4: Projected Nodal Price Spreads vs. PG&E DLAP (Monthly Average over 13 years)

Figure C-5 also indicates that the energy value of the City’s solar resources is projected to be especially low during the spring and early summer months, when system-wide loads are relatively low. Unfortunately, this also happens to be a period when a significant proportion of the total annual solar generation occurs.
C. ANALYSIS FINDINGS

Relative Net Value of Portfolio Resource Options
The primary driver of the City’s decision on what amount of the Western contract to sign up for starting in 2025 will be the total cost and value of the resource relative to other available options. And on this point, based on the output of the FNM optimization tool and the spreadsheet model, it appears that Western has the potential to be a relatively valuable/low-cost resource; however, for a variety of reasons (described in more detail in the report and Attachment D), it also has by far the most uncertainty around its future costs.

The expected net value of Western and several potential new contracts, as determined by the scenario-based spreadsheet analysis, is shown below in Figure C-6 for the 2025-2030 period. Figure C-6 presents the net value of each resource based on its energy values (based on each resource’s LMP forecast), along with the ancillary services value provided by Western, the value of the RECs generated by the renewable resources, and each resource’s RA capacity. Note that in Figure C-6 the expected net value of some resources is negative (less valuable than projected market value), due to the fact that (aside from Western) the cost of each resource includes the cost of renewable attributes in addition to energy, and because a primary goal of a long-term agreement such as a PPA is to hedge and manage exposure to future price volatility.
One of the primary messages of Figure C-6 is that there is a tremendous amount of uncertainty around the net value of Western, as indicated by the large uncertainty bars featured on that data series.\(^5\) It should be noted that the uncertainty shown in Figure C-6 is illustrative only, and based on staff’s best estimate of the potential range of future Western contract costs.\(^6\) It should also be noted that this uncertainty is heavily biased toward the negative direction: there is limited “upside” uncertainty while there is a great deal of “downside” uncertainty, largely related to pending environmental regulatory issues.

Other significant takeaways from Figure C-6 are that wind and solar resources appear – at this point – to be fairly competitive with Western (on an expected basis). However, geothermal resources – despite a significant cost reduction in recent years – are still not cost-competitive with other resource options. It should also be noted that while in-state wind appears to be the most attractive renewable resource option in this analysis, there is currently a very limited amount of new in-state wind capacity being developed. Staff will certainly consider this resource type in future procurement efforts, but it should not be expected to be available.

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\(^5\) Figure C-6 does not include market price uncertainty or hydrological uncertainty; the uncertainty range shown for Western represents purely regulatory and litigation-related cost uncertainty.

\(^6\) See Attachment D for further discussion on the sources and potential magnitude of this uncertainty.
Using the scenario-based spreadsheet model, staff also investigated the total costs of various combinations of portfolio resources under several Western cost scenarios. Under the expected cost scenario, portfolios with the maximum possible allocation of post-2024 Western (and a small amount of in-state wind) are the lowest-cost options. A portfolio with a smaller amount of Western allocation (approximately half of the total possible allocation available to the City) along with local solar and DERs also performs well, although this portfolio assumes that the City can obtain a large quantity of very low-cost (8.5 ¢/kWh) local solar, which is not likely to be feasible. The portfolio where the City replaces all of its Western allocation with in-state solar results in the highest total cost over the analysis period, among the portfolios staff considered. However, the analysis shows that if Western costs increase by 20% from the expected scenario, other resource options appear to be approximately as low-cost as Western.

**Portfolio Fit**

Another of the key findings from the spreadsheet model – and another important factor in the City’s decision around the 2025 Western contract – relates to the hourly portfolio fit of different resource types. The degree to which resources “fit” in the City’s existing supply portfolio will determine how reliant the portfolio is on grid power (and, as a result, how exposed it is to market prices). Figure C-7 below shows average hourly generation profiles for each month (one average day per month is shown) for Western and other potential new resources relative to the City’s average hourly load. All values are normalized to the City’s average hourly load, so, for example, if the City’s average hourly load was 100 MW, then a hypothetical 50 MW solar resource in the Central Valley would have a peak generation value of 0.5 in Figure C-7. Given that the City’s total resource supplies from long-term contracts exceed total load in the spring and summer months, while the opposite is true during the fall and winter months, Figure C-7 indicates that out-of-state wind (from New Mexico or Oregon), which produces more energy in the fall and winter months, would be a good complement to the City’s existing portfolio of resources. In-state wind (in the Solano hills, where the City’s two wind projects are located) and solar, on the other hand, exacerbate the City’s portfolio fit problem, as they produce more energy in the spring and summer months.
Grid Reliance of Different Electric Portfolios

The current electric portfolio is dispatched to maximize economic value, and is seasonally surplus in the spring and summer months and short in the fall and winter months. This means that rather than matching resources to load, the City’s portfolio is expected to experience hourly gross surpluses relative to load by a total of 263 GWh in 2018 (primarily in the spring and summer months), as well as hourly gross deficits of 201 GWh (primarily in the fall and winter months). Therefore the City is expected to have a net surplus position of about 62 GWh. Replacing 50 GWh of solar generation (approximately what a 20 MW facility generates in a year) with a flat, inflexible renewable resource would reduce the hourly gross surplus volume by 13 GWh – or about 1.4% of the City’s annual load.

Table C-1: Palo Alto Gross Hourly Electric Supply Surplus and Deficit Positions (in GWh), Estimated for Calendar Year 2018

<table>
<thead>
<tr>
<th>2018 Electricity (GWh per year)</th>
<th>Hourly Surplus Positions</th>
<th>Hourly Deficit Positions</th>
<th>Hourly Net Position [+ ] Surplus, [- ] Deficit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current Portfolio</td>
<td>263</td>
<td>(201)</td>
<td>62</td>
</tr>
</tbody>
</table>
Hourly Carbon Emissions of Different Electric Portfolios

Staff also examined how the electric portfolio’s resources and dispatch strategies impact its hourly carbon emissions. The 2018 projected hourly average carbon intensity of the California electricity mix per quarter from the California Air Resources Board⁷ was used as a first approximation. Although these emissions profiles are estimated for 2018 and are quarterly averages, they help to understand the carbon intensity of the grid when the City’s resources exceed its load versus when its resources are less than its load. Table C-2 shows that the current electric portfolio produces net annual emissions of roughly 4,800 metric tons of carbon dioxide per year (mTCO₂/yr). This annual “net” calculation is assuming the City is credited for the emissions “displaced” when its resources exceed load. Using this same netting methodology, replacing 50 GWh of annual generation from solar resources with a baseload renewable resource, such as geothermal or biomass, would lower the net annual emissions of the electric portfolio by 90% – to roughly 500 mTCO₂/yr. However, if the City is not credited for any displaced emissions during its hourly surplus period, its gross annual emissions total would be 68,000 mTCO₂/yr. And replacing 50 GWh of solar generation with baseload renewable generation would result in about a 7% reduction in emissions, to 63,000 mTCO₂/yr.

Table C-2: Palo Alto Gross Hourly Carbon Emissions and Displacements (in 1,000 mTCO₂), Estimated for Calendar Year 2018 Based on Average Hourly California Grid Carbon Intensity

<table>
<thead>
<tr>
<th>2018 Carbon (1,000 mTCO₂ per year)</th>
<th>Displaced on Hourly Basis</th>
<th>Emitted on Hourly Basis</th>
<th>Net on Hourly Basis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current Portfolio</td>
<td>(63)</td>
<td>68</td>
<td>4.8</td>
</tr>
<tr>
<td>Replace Solar with Baseload</td>
<td>(62)</td>
<td>63</td>
<td>0.5</td>
</tr>
<tr>
<td>(50 GWh)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

D. ADDITIONAL PORTFOLIO ANALYSIS EFFORTS TO INFORM WESTERN CONTRACT DECISION

As noted in the report, staff expects to do a significant amount of work in the next few years to better understand the cost uncertainties relating to the Western resource, and to manage future load and resource uncertainties. Some of the efforts noted involve expanding and extending the portfolio analysis work presented here. Specific steps that staff plans to take in the coming years to advance the current portfolio analysis include:

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⁷ The projected 2018 average hourly emissions of the California electricity mix were taken from Table 7-2 on page 137 from the report from the California Air Resources Board located here: https://www.arb.ca.gov/regact/2018/lcfs18/appa.pdf
1. Extending the analysis period beyond 2030, to capture the full length of the post-2024 Western contract and any future renewable PPAs.
2. Updating the resource LMP forecasts, estimated contract prices, and other key input assumptions.
3. Further analyzing the projected costs, output levels, and flexibility of the renewed Western contract, to reduce the amount of outstanding uncertainty around this resource.
4. Performing additional scenario analysis around the various assumptions that go into the modeling of different portfolio options, including accounting for the operational impacts on Western of the regulatory uncertainties facing it.
5. Evaluating specific carbon-free resource options – a task that may be best accomplished by issuing a Request for Proposals (RFP) in order to get up-to-date, actionable price data. This RFP could look at acquiring new resources to replace the Western contract after 2024, as well as swapping one or more solar resources for baseload or wind resources, in order to improve the overall fit of the supply portfolio to the City’s net load.
Staff, along with NCPA and other joint action partners, actively manage electric supply portfolio costs and cost uncertainties to mitigate adverse impacts. Summarized below are nine important sources of cost uncertainty that will be actively managed. In addition to these nine supply-related uncertainties, staff will also advocate for low-cost and reliable transmission infrastructure to deliver supply resources to Palo Alto.

The uncertainty that will have the largest impact on the portfolio is the 2025 Western contract (item A below). In comparison, the other risks are relatively small. At present, the annual electric supply cost (related to energy purchases only) is $65 million, as shown in Attachment B. The long-term cost uncertainties identified below have the potential to increase this cost by 25% to 50% in the next 10 to 20 years. The potential also exists for this cost to be lowered by 5% to 10%, in the event of more favorable cost allocation to CVP Power customers and lower energy market prices.

### Table 1: Electric Supply Portfolio – Long-Term Cost Uncertainties, Impacts and Mitigation Strategies

<table>
<thead>
<tr>
<th>Long-Term Cost Uncertainties</th>
<th>Description</th>
<th>Cost Impact</th>
<th>Relative Impact</th>
<th>Mitigation Strategy</th>
</tr>
</thead>
<tbody>
<tr>
<td>A) Cost &amp; operations of Western hydroelectric resource</td>
<td>Future cost of Western resource is highly uncertain and depends on costs allocated to the Central Valley Project (CVP) Power Customers for system improvements. These uncertainties include: environmental restoration cost, water delivery timing and priorities, Western transmission upgrade needs, etc. The energy available from the resource in the long term is also dependent on various environmental laws that control water releases, and impacts due to climate change.</td>
<td>The long-term average unit cost of Palo Alto’s energy is expected to be 3 to 5 cents/kWh, in 2024 real dollars, over the 30-year life of the contract. The uncertainty could increase this cost range by about 1 to 2 cents/kWh. The potential also exists for lower costs if cost allocations to CVP Power Customers are reduced or if CVP generation is able to take greater advantage of market opportunities.</td>
<td>High: Resource accounts for almost 40% of the portfolio and contract requires commitment for a 30 year duration starting 2025.</td>
<td>In collaboration with joint action partners, ensure costs are prudently incurred and allocated to power and irrigation customers on a cost-causation basis. Advocating for the Western contract to include the option for Palo Alto and other Western power customers to lower their share of Western resource if the resource become uneconomical over the 30 year term of the contract.</td>
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<td>B) Frequency and magnitude of economic curtailment of solar PV resources in the Central Valley</td>
<td>As the unit cost of solar generation declines and RPS goals increase, solar’s share of the state’s energy mix is expected to rise substantially by 2030. With the marginal cost of solar production at zero, at certain times when there is excess energy in the system, it may be best for Palo Alto to pay the contract price for energy, but instruct the solar project not to produce. This economic curtailment effectively increases the unit cost of the solar resource.</td>
<td>Solar accounts for about 32% of Palo Alto’s portfolio, at an average cost of 7 cents/kWh. If 10% to 30% of total solar output is curtailed, the annual energy cost may increase by $1 to $3 million per year if replacement power must be purchased as a result.</td>
<td>Low-Medium: It is conceivable that up to 50% of spring solar production could be curtailed.</td>
<td>Negotiate contracts with solar vendors to fairly allocate the costs of increased curtailment, such as securing a limited amount of curtailment free-of-charge and increasing the City’s right to unlimited economic curtailment. Evaluate merits and cost-effectiveness of on-site storage. Implement variable customer retail rates to incentivize energy usage when market prices are close to zero or negative.</td>
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<tr>
<td>Long-Term Cost Uncertainties</td>
<td>Description</td>
<td>Cost Impact</td>
<td>Relative Impact</td>
<td>Mitigation Strategy</td>
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<td>C) Relicensing NCPA’s Calaveras hydroelectric project</td>
<td>Calaveras hydro project license needs to be renewed by 2032; cost for renewal is estimated at $50 million, but it may be higher and/or Palo Alto share may diminish.</td>
<td>Current average unit cost of this resource is 8 to 10 cents/kWh, but beginning in 2032 (after the debt is paid off), unit cost is expected to drop to 3 to 4 cents/kWh. The relicensing cost and related obligations may increase this cost to 4-5 cents/kWh.</td>
<td>Low: Resource accounts for 13% of the portfolio and resource cost is expected to be very cost-effective beginning in 2032.</td>
<td>As the operator of the hydro project, NCPA has been a responsible member of the Calaveras County community, and anticipates being able to operate the project to its members’ benefit well beyond 2032.</td>
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<td>D) Seasonal variation in CAISO energy market prices</td>
<td>Palo Alto uses funds from the sale of excess resources in the spring and summer months (Q2/Q3) to fund energy purchase needs in the fall and winter months (Q4/Q1). If the Q2/Q3 prices decline and Q4/Q1 prices increase, the net annual cost of energy will increase for Palo Alto ratepayers.</td>
<td>Currently the surplus of energy supplies in the Q2/Q3 period make up about 30-50% of energy needs during these periods and a similar fraction of energy needs for the Q4/Q1 period is in deficit and has to be purchased. Though these seasonal annual forward sale/purchase transactions are undertaken at the same time once a year, an additional divergence of these seasonal prices could increase Palo Alto cost by $2 Million per year.</td>
<td>Low: The dollar amounts associated with such adverse movement of seasonal prices are relatively small.</td>
<td>Undertake a seasonal buy-sell transaction annually to balance the portfolio, thus avoiding the risk of such seasonal price divergence within a year. Staff is considering undertaking such seasonal buy-sell transactions on a forward basis over multiple years. Another strategy is to procure long-term resources that lower the portfolio’s seasonal imbalance; however, this is a low priority because the economics of such a rebalancing are not favorable.</td>
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<td>E) Changes in overall energy market price and changes in carbon allowance prices associated with State’s cap-and-trade program</td>
<td>The market price of cap-and-trade program carbon allowances is expected to increase considerably, as allowances made available by the state decrease in the coming years. Such increases could raise the cost of natural gas-fired electric generation and overall energy prices in the state. Greater penetration of renewables could also lower market prices below current projections, resulting in a lower overall cost.</td>
<td>Since Palo Alto’s electric supply closely matches projected annual demand, higher market prices will only minimally impact supply cost.</td>
<td>Low: The City has relatively low exposure and does not own or have long-term contracts with any fossil-fuel generation.</td>
<td>Continue to procure long-term carbon-free supplies to closely match demand. Implement flexible demand response programs to deliver energy and carbon savings during high-cost hours.</td>
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<td>F) Default of Renewable Energy Suppliers</td>
<td>If energy market prices rise and renewable energy projects experience financial distress, suppliers may default and Palo Alto would need to purchase higher cost resources in the market to meet loads.</td>
<td>Difficult to quantify; impact depends on renewable energy market prices and the viability of Palo Alto’s projects – these two factors are not closely correlated.</td>
<td>Low: The likelihood of experiencing high renewable energy prices in tandem with a project supplier defaulting is low.</td>
<td>Palo Alto retains performance bonds for renewable energy projects that could be drawn on to mitigate this risk.</td>
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<td>G) Increased market prices related to load-following capacity and ancillary services</td>
<td>In addition to energy, Palo Alto also has an obligation to provide flexible capacity resources to balance loads and resources in the CAISO market. As intermittent resource penetration increases, the cost or value of such flexible resources will also increase and could result in higher cost to the electric ratepayer.</td>
<td>Palo Alto currently pays about $1 Million per year for such services, which are largely offset by revenues from Calaveras hydro, which provides such flexible capacity to the market. However, as the portfolio share of solar PV increases, Palo Alto will be required to procure greater amounts of flexible capacity.</td>
<td>Low: The financial exposure is not large. Energy storage mandates could also have a dampening effect on the market prices for such services.</td>
<td>Continue to monitor exposure to this uncertainty and evaluate long-term investment in flexible capacity products such as energy storage systems as prices decline.</td>
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<td>F) Customer load profiles change and loss of customer loads available for the City to serve</td>
<td>Due to customer sited DERs and other competitive factors, Palo Alto loads could decrease by 5-10% by 2030, and potentially up to 25% by 2050. Also, the hourly and daily load profile could also change considerably.</td>
<td>If such load loss materializes and the market value of the excess energy resources become less than cost, the costs to serve the remaining customers will rise. Exposure is estimated at $1 to $2 Million per year under a 10% load loss scenario. Upside potential also exists if excess energy can be sold at a price above cost; however, this is viewed as unlikely.</td>
<td>Low: in the next 5-10 years; Medium in the greater than 20 year time frame.</td>
<td>To the extent possible, maintain a 5-10% open position beyond 5 years and at least 20% open position beyond 20 years.</td>
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<td>I) New legislative and regulatory mandates</td>
<td>New legislative and regulatory mandates (not known at this time) have the potential to add to resource and administrative costs.</td>
<td>Cost associated with such unknown uncertainty is not readily quantifiable.</td>
<td>Low: in the next 5-10 years; Medium in the greater than 20 year time frame.</td>
<td>Continue to partner with Joint Action Agencies such as NCPA, CMUA, APPA to lower this exposure. Municipal utilities in California in general have been successful in this arena in the past. Prior successes include avoidance of a high-cost storage mandate from the State. Continue to value flexibility of resources.</td>
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