VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 14

TO: Board of Directors

FROM: Gordon Samuel, Assistant General Manager & Director of Power Services

SUBJECT: Consider increasing VCE's Existing 80% Renewable by 2030 Goal

DATE: July 13, 2023

RECOMMENDATIONS

1. Receive presentation and provide feedback on VCE's power portfolio content goals.
2. Increase the current 80% renewable goal by 2030 to 100% renewable by 2030 and substitute the 25% renewable local component goal with a goal of 25% of future storage amounts to be from local installations.
3. When conducting solicitations state a preference for locally sited resources.

BACKGROUND

Prior to VCE's launch in June 2018, the Board adopted a goal for VCE's power content to target 80% renewables by 2030. The goal also set a requirement that 25% of this amount should be from local resources. At the time this was a very ambitious goal, and some may still consider this to be a stretch or at least a sufficient target. Others may believe this goal does not go far enough. Since this goal was adopted, VCE has entered into several long-term power purchase agreements (PPAs) and has been working towards fulfilling these goals.

Guiding Documents – Carbon Neutral Study and 2022 Integrated Resource Plan

In the second half of 2021 and early 2022, staff completed a 100% carbon neutral by 2030 study (CNx2030) which considered not only being carbon neutral but also 100% renewable (100% Carbon Free Portfolio Study (Final)). In 2022, VCE submitted its integrated resource plan (IRP) to the California Public Utilities Commission (CPUC) (Integrated Resource Plan (IRP) filed 11/1/2022). This IRP also studied various portfolios from 2023-2035 with the primary focus to be at or below a specific emissions target in an effort to reduce greenhouse gases (GHG) at the lowest cost. As a result of VCE's procurement and study efforts, a reasonable roadmap is beginning to emerge which presents an opportunity to revisit the current power content goal adopted in 2018.

During the November 17, 2022 Community Advisory Committee (CAC) meeting, the Committee voted unanimously to recommend that the Board modify the existing goal. The CAC recommended that the Board approve a new goal which is 100% renewable by 2030 with 25% of the content sourced from local resources. A key point expressed by several CAC members who spoke in support of increasing the goal believed that it provides a reasonable target for VCE to aspire towards. Unfortunately, in November 2022, Staff did not have the supporting analysis of the advantages/disadvantages associated with the CAC proposed modification of the current portfolio goal – specifically the 25% local component. Staff reported this CAC recommendation to the Board in late 2022 and received direction from the Board to return in mid-2023 with an analysis of setting a more aggressive 2030 renewable target.

Based on that direction, staff engaged the portfolio modeling services of First Principles Advisory (FPA), the firm that performed the portfolio modeling for VCE's 2022 IRP. FPA's familiarity with the VCE portfolio was a logical reason to have them conduct this additional modeling. At the February 2023 Board meeting, the Board approved a contract with FPA for the additional modeling with a commitment from staff to bring the results and recommendation to the CAC in June and the Board in July 2023.

<u>VCE Current Renewable Portfolio</u>
VCE's has signed seven renewable PPA consisting of photovoltaic (PV), hybrid (PV + storage) and geothermal. These PPAs account for approximately 680 annual GWHs or approximately 70% of VCE's retail load (2030).

Table 1 – VCE's Executed Long-Term Renewable PPAs

Long Term PPAs	Actual or Expected COD	Capacity*
Resurgence Solar I	7/7/2023 (active)	90 MW PV, 75 MW BESS (250,000 MWhs)
Aquamarine Solar	9/22/2021 (active)	50 MW PV (130,000 MWhs)
Putah Creek Energy Farm	10/15/2022 (active)	3 MW PV, 3 MW BESS (7,600 MWhs)
Gibson Solar	6/1/2025	13 MW PV, 13 MW BESS (50,000 MWhs)
Willy 9 Chap 2**	12/31/2023	72 MW PV, 36 MW BESS (210,000 MWhs)
Ormat Geothermal	Varies by project, but as early as 2025	4.63 MW (35,380 MWhs)
Fish Lake Geothermal	June 2024	0.42 MW (3,460 MWhs)
* All Battery Energy Storage Systems (BESS) are 4-hour duration, except the Gibson Solar project is a 5-hour battery system. Approx annual MWhs shown. ** Formerly Willow Springs Solar 3. Name changed at the request of the CAISO.		

ANALYSIS
Staff, working with FPA, identified seven scenarios to model. Four assuming a future natural gas price curve that would be considering a P50 curve and three at a higher price P95 curve[1]. For the purposes of this report, staff elected to focus on the results associated with the P50 analysis. Note: if natural gas prices are more in-line with the P95 assumption this does have a material cost impact on the portfolio depending on the type of renewable resources selected.

[1] P50 and P95 represent the confidence level of a cost not being exceeded. A P50 value has a 50% probability that it will be exceeded, whereas, a P95 only has a 5% probability of being exceeded.

Table 2 – Four Scenarios Modeled Based on P50 NG Curve

Scenario	NG Price	2030 RPS Target	Local RPS Target
1.a (current goal)	P50	80%	25%
1.b	P50	100%	25%
1.c	P50	100%	-
1.d	P50	80%	-

Scenario 1.a can be considered the base case or business as usual (BAU). This scenario is the current VCE goal. Scenario 1.b increases the renewable percentage to 100% by 2030 as well as maintains the current 25% local renewable component. Scenario 1.c increases the renewable percentage to 100% but only considers the two existing local PPAs that VCE has executed (Putah Creek and Gibson[2]). Finally, Scenario 1.d maintains the current 80% renewable by 2030 and only considers the two existing local PPAs that VCE has executed (Putah Creek and Gibson). The purpose of identifying these four scenarios was to establish a range of potential cost outcomes.

The portfolios from each of the scenarios are slightly different but the primary choice of eligible renewable technologies does not vary (note: the modeling does allow for the selection of other technologies such as biomass, off-shore wind, etc but only selects resources that are the best fit for the portfolio). Table 3 below identifies the incremental capacity additions (additions above what VCE has already contracted) for each scenario.

Table 3 – Cumulative Incremental Capacity Additions

Cumulative MWs - Incremental Needs (2030 / 2035)								
	1a - 80% RPS, 25% Local		1b - 100% RPS, 25% Local		1c - 100% RPS, 8% Local[3]		1d - 80% RPS, 8% Local[3]	
	2030	2035	2030	2035	2030	2035	2030	2035
Wind[1]	20	75	20	50	100	155	90	145
Geothermal	25	35	25	35	40	50	40	50
Storage[2]	34	89	37	70	55	115	50	107
Local hybrid (PV+S)	45	65	60	84	-	-	-	-
Total								
1) Wind is on-shore. Off-shore wind is not economical in this planning horizon								
2) Storage in this table includes duration from 4 hr to 12 hr								
3) "Local" in these scenarios assumes only Putah Creek and Gibson project (approx 8%)								

As shown the local hybrid renewable resources are assumed to be PV + storage as that is the most realistic resource available in Yolo County as the county does not have significant geothermal or wind resources and the local biomass resources have proven to be quite costly. Unfortunately, PV land

[2] These two local projects represent approximately 8% of VCE's renewable portfolio.

usage is significant which can have impacts on prime agricultural land which presents policy trade-offs and can be difficult to permit. To achieve the current 25% local goal, the amount of new local capacity would be between 65 MW and 84 MW. Although this amount is technically feasible, based on direct experience staff observes that it will be difficult to permit locally, the costs will be at a premium compared to installation in other regions of the State, and it installs a technology that VCE otherwise would not select as the portfolio would benefit from additional diversification (e.g. wind).

Scenario Costs

Table 4 below identifies the net present value (NPV) cost trade-offs between each scenario. All scenarios are measured off Scenario 1.a (BAU scenario). Scenario 1.b is $23.5 million more than the BAU case, similarly Scenario 1.c is $33.4 million cheaper than the BAU case (or nearly $57 million cheaper than Scenario 1.b). Scenario 1.d is the lowest cost of all cases. An important point to highlight is the incremental cost to go from 80% (1.d) to 100% (1.c) renewable is not unreasonable and staff believes this is something the Board should consider. It is clear from the model runs that portfolio costs are amplified when factoring in additional local resources.

Table 4 – Scenario Cost Comparisons

Scenario	NG Price	2030 RPS Target	Local RPS Target	2024-2035 NPV (2022 $M)	Delta (2022 $M)
1.a	P50	80%	25%	619.6	0
1.b	P50	100%	25%	643.1	23.5
1.c	P50	100%	-	586.1	-33.4
1.d	P50	80%	-	575.7	-43.9

Goals / Policies of other Load Serving Entities (LSEs) in California – Including CCAs

Although each LSE's situation is different, it is important to understand what other LSE's have committed to. Numerous LSEs do have "aspirational" goals of achieving 100% renewable and clean power by 2030. Many LSEs intentionally include the term "clean" in their goals as this allows some flexibility to meet some of the content with resources such as large hydro or nuclear (both are defined as GHG-free or clean but neither qualify as renewable per the CPUC definition). For reference, Attachment 1 identifies the policies of many LSEs in California.

Strategic Plan

VCE's current Strategic Plan contains the following goal: "Manage power supply resources to consistently exceed California's Renewable Portfolio Standard (RPS) while working toward a resource portfolio that is 100% carbon neutral by 2030." By definition, California RPS renewable energy is also carbon free. Therefore, technically VCE would be exceeding its strategic plan goal by modifying to a 100% renewable goal by 2030. In addition, aspects of the strategic plan are currently being reviewed so any new goals can be incorporated into the latest version.

Community Advisory Committee Feedback
Staff presented this topic to the CAC in June. The topic generated a robust discussion of the pros and cons of increasing the goal to 100% as well as the local component modification. The CAC was supportive of Staff's recommendation and further requested a slight enhancement of the recommendation. The CAC proposed (and staff supports), that when VCE conducts solicitations it states there is a preference for locally sited resources. In addition, the CAC believes the definition of "local" to be expanded to include Yolo County and the adjacent counties.

CONCLUSION
Staff is seeking Board feedback on modifying the existing power portfolio goal. Staff findings based on the scenario analysis:

1) With the current portfolio trajectory staff believes achieving 100% renewable is a reasonable and fiscally sound goal for the Board to consider.
2) Staff also believes the 25% local component should be revisited for two reasons:
    a. The primary local renewable resource is solar (PV). From the modeling, additional solar is not a resource VCE needs as VCE needs to diversify to other renewable technologies to achieve a more balanced renewable portfolio.
    b. The cost to achieve the 25% local requirement should be considered as this decision is discussed. It is substantially more costly to VCE's customers to meet this component of the goal by 2030 and beyond. Based on the analysis, savings of up to $33M may accrue over the next 10 years vs. BAU (see Table 4).
3) Stand-alone storage resources, which enable the installation of more intermittent renewable resources in California (e.g. solar, wind), is a resource that could be considered for Yolo County.
    a. Permitting stand-alone storage is likely to prove to be more stream-lined as the footprint of the underlying disturbed land is much smaller than solar.
    b. VCE, as well as the grid, need storage.

Attachments
1. California LSE's renewable goals
2. Study Results from First Principles Advisory (redacted)

Attachment 1

Renewable Energy Goals of CCAs and other electric utilities in California (as of May 2023)

LSE Name	Goal Summary
IOUs	
PG&E	net-zero energy system by 2040
SCE	RPS
SDG&E	RPS
Regional/Municipal Districts	
IID (Imperial Irrigation District)	RPS
LDWP	80%/90% RPS by 2030, 100% carbon-free by 2035
SMUD	zero carbon emission power supply by 2030
CCAs	
Apple Valley Choice Energy	RPS
Central Coast Community Energy	100% clean and renewable energy by 2030
City of Palmdale	RPS
City of Pomona	RPS
City of Santa Barbara	75% renewable / 100% carbon-free by 2030 (default rate)
Clean Energy Alliance	100% renewable by 2035
Clean Power Alliance	RPS
CleanPowerSF	100% renewable electricity by 2025, and 100% renewable energy (0% fossil fuels) by 2040
Desert Community Energy	RPS plus 100% carbon-free product as default for customers in Palm Springs
East Bay Community Energy	100% net-zero carbon annually by 2030, 100% clean energy on a net annual basis by 2030, exceed state RPS by 20% per year
King City Community Power	RPS
Lancaster Choice Energy	RPS
Marin Clean Energy	60% minimum renewable, default rate at 98.3% renewable as of 2021 (including large hydro)
Orange County Power Authority	RPS
Peninsula Clean Energy	100% renewable by 2025, including hourly matching (i.e., time-coincident basis)
Pico Rivera Innovative Municipal Energy	50% renewables (default rate)
Pioneer Community Energy	RPS

Rancho Mirage Energy Authority	RPS
Redwood Coast Energy Authority	100% clean and renewable by 2025, plus 100% local renewable energy by 2030 (local resources located within the Humboldt Local Capacity Area)
San Diego Community Power	75% in 2027, 85% in 2030, and 100% in 2035 renewable; 15% new storage in Member Agencies' territories by 2035; 600MW of new utility scale projects within San Diego and Imperial Counties by 2035
San Jacinto Power	RPS
San Jose Clean Energy	100% carbon neutral and renewable (annual basis) by 2030, with 0% fossil fuel by 2050
Silicon Valley Clean Energy Authority	50% - 52% renewable currently, 60% - 62% renewable in 2030; 100% of energy needs with carbon-free electricity on annual basis, longer-term goal of carbon-free on 24x7 basis
Sonoma Clean Power	Board policy of 50% renewable by 2020; Internal goal of 100% hourly marginal emissions mitigation by 2026 and 80% Winter Night Reliability by 2030
Valley Clean Energy Alliance.	80% renewable by 2030

Attachment 2 – Study Results from First Principles Advisory (redacted)

First Principles Advisory

VCE Spring 2023 Modeling Exercise

Contents

First Principles Advisory

Executive Summary

First Principles Advisory

- VCE's current baseline scenario (i.e., 80% RPS energy by 2030 with a 25% local carveout) increases the NPV of the portfolio by $20-64M across the 2024-2035 planning horizon
  - Estimated cost premium is dependent on multiple variables, including (but not limited to) the price of NG and VCE's risk management policy regarding market transactions
- Increasing the RPS target to 100% and keeping the 25% local carveout will result in an additional NPV expense of $14-24M relative to the baseline scenario
- Assuming solar-storage hybrid projects is the only available technology that can be built in Yolo County, VCE's portfolio heavily is concentrated in solar and 4-hr storage and has limited ability to diversify its supply with other technologies
  - Onshore wind, geothermal, and storage greater than 4 hours of duration constitute a greater share of contracted supply for the scenarios where the local constraint is not active
- Combined, the recently passed IRA legislation and the current strained market conditions for li-ion based storage projects have significantly increased the opportunity cost associated with VCE's local generation policy
  - Li-ion costs have increased 15-25% whereas cost of alternatives have decreased 20-30%
- Despite current high RA-only prices, VCE will be better off if they wait for market conditions for li-ion storage to settle and not lock in high price long-term (i.e. 10yr+) contracts
  - Note interconnection and project constructions delays increase the complexity of the near-term procurement strategy

Key Recommendations

- 100% (annual) RPS target by 2030 is economically feasible
  - Policy would not add significant costs to the portfolio
  - Allowing stand-alone storage projects located in Yolo County to qualify can help reduce the associated cost premium
- Path dependency matters -> need to know the end destination and what’s allowed; update as you go
  - A clearly defined RPS / GHG policy and risk management policy is necessary to ensure portfolio is heading in the desired direction
- Understanding of current PPA market is critical
  - Run an all-source solicitation annually to obtain timely information on technology costs
  - Execute agreements when favorable prices of desired technologies present themselves
- Curtailment risk is only partially accounted for in current modeling approach
  - A site-by-site assessment should be taken in future modeling exercises
- Benefits of customer programs should be fully explored to contain costs and increase flexibility
  - Updated TEA load forecast assumes VCE grows its annual load by 35% while increasing its peak demand by only 18%

Financial Summary

First Principles Advisory

Index	Natural Gas Price	RPS 2030 Target	Local RPS Requirement	Local Hybrid Capacity (MW)	2024-2035 NPV (2022 $M)	Delta (2022 $M)
1.A	P50	80%	25%	65	619.6	0
1.B	P50	100%	25%	84	643.1	23.5
1.C	P50	100%	n/a	0	586.1	-33.4
1.D	P50	80%	n/a	0	575.7	-43.9
2.A	P95	80%	25%	65	591.6	0
2.B	P95	100%	25%	84	613.2	21.6
2.C	P95	100%	n/a	0	527.4	-64.3

- In the P50 NG scenario, increasing VCE's 2030 RPS target and keeping the 25% local requirement results in an additional charge of $23.5M in present value relative to VCE's current policy (e.g., 80% RPS with a 25% carve out)
  - If VCE increases their 2030 RPS target to 100% but doesn't require any additional local projects results in a cost savings of $33.4M
- In the P95 NG scenario, the local premium is $21.6M

*Scenario 2.D not run in GridPath because model doesn't bind on RPS constraint in scenario 2.C

Local Project Characteristics

- 1MW-4MWh of storage for every 1 MW of solar
- Solar capacity factor: 33%
- Battery roundtrip efficiency: 86%
- Local hybrid project is ~40% more expensive than latest technology costs curves posted in CPUC's latest Inputs and Assumptions (I&A) document

Cumulative Capacity (MW)

Year	80% RPS Target	100% RPS Target
2028	22.5	30
2030	45	60
2032	55	72
2035	65	84

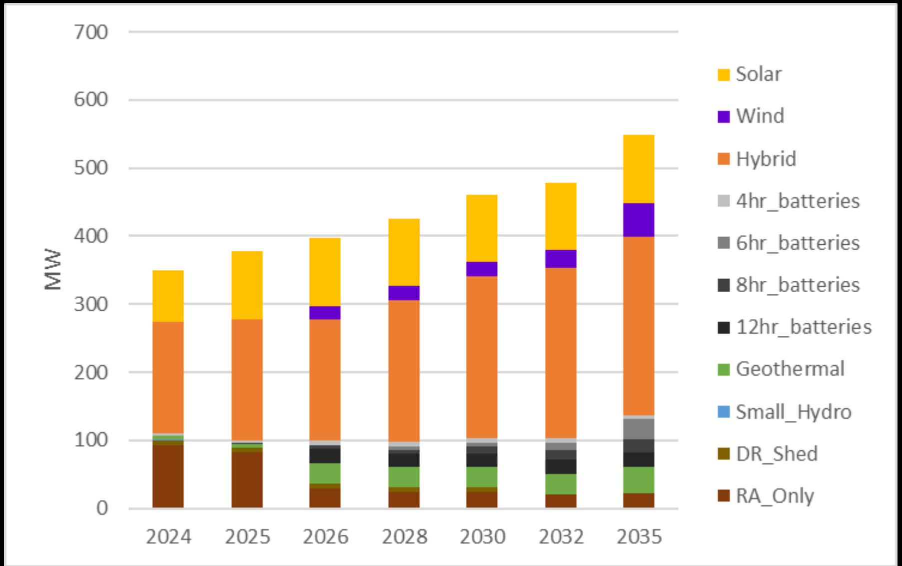
Year	2028	2030	2032	2035
Energy Price ($/MWh)	54	50	50	45
Capacity Price ($/kW-m)	10.75	9.50	8.00	7.00
"All-in Price" ($/MWh)	100	90	84	75
Non-Local Hybrid All-in Price ($/MWh)	70	64	60	54

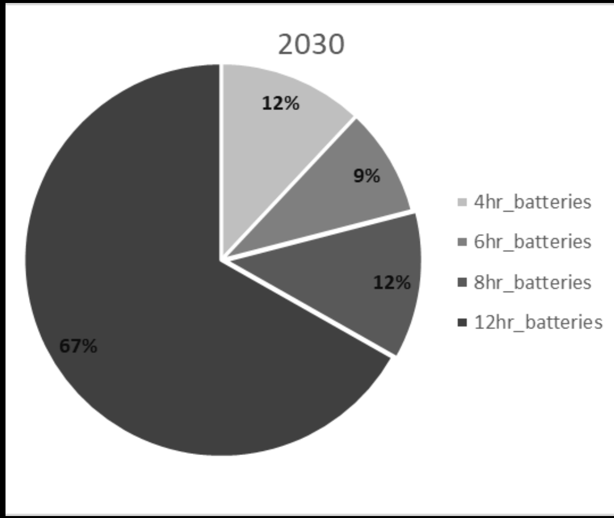
Detailed Results of Scenario 1.a

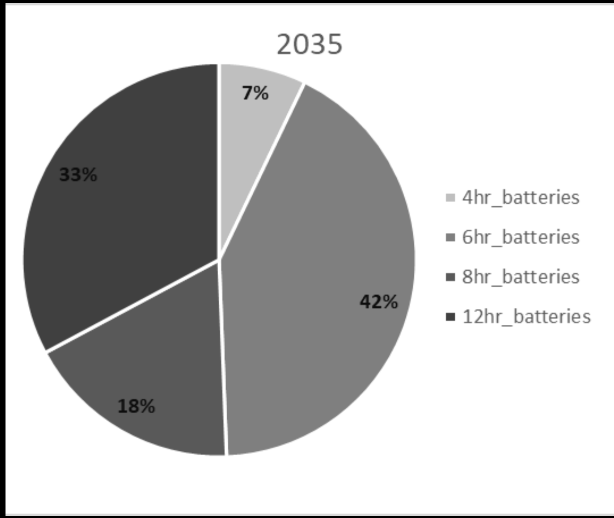
Scenario 1.A: System Buildout (nameplate)

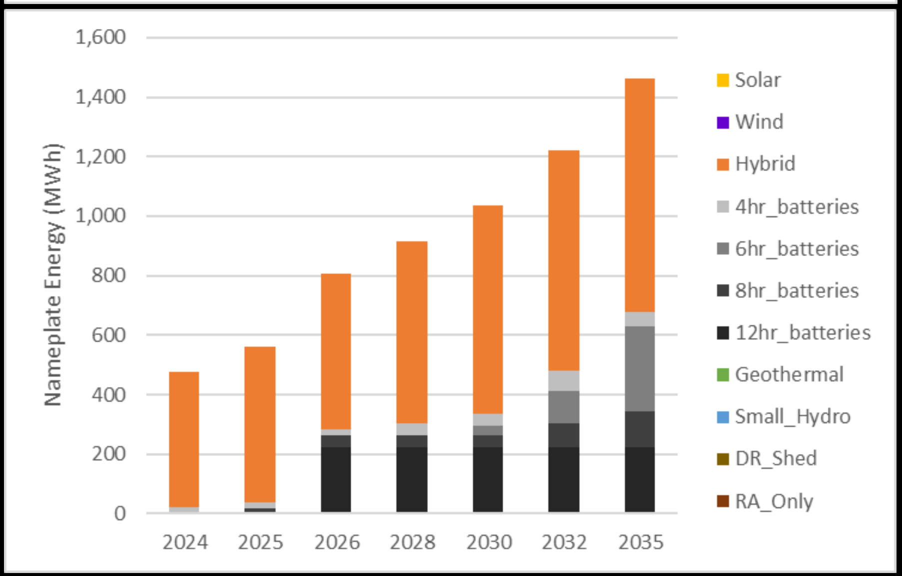
First Principles Advisory

- Solar (stand-alone or hybrid) makes up 73% (60%) of nameplate capacity in 2030 (2035)
- Hybrid storage makes up 67% (54%) of nameplate capacity in 2030 (2035)
  - Hybrid storage is 4 hours in duration
- Dashboard File:
  - MW
    - Portfolio Summary I: columns B:H
    - Portfolio Summary II: columns D:J
  - MWh
    - Portfolio Summary I: columns L:R
    - Portfolio Summary II: columns P:V









Scenario 1.A: Generation (contracted)

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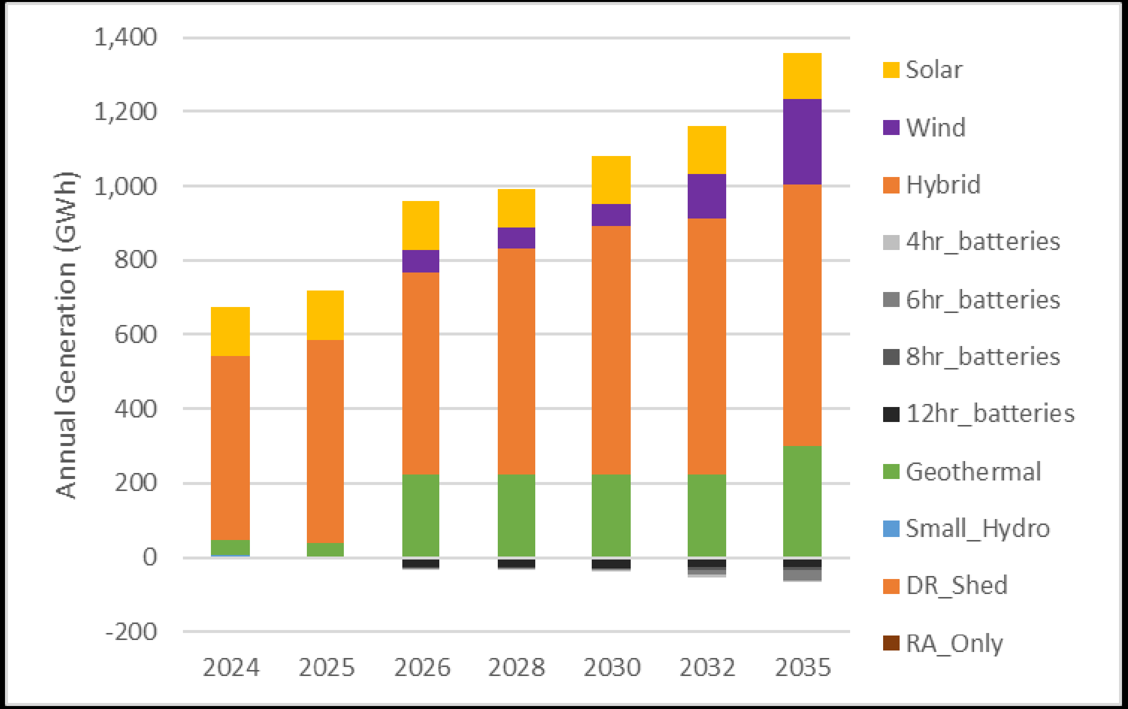
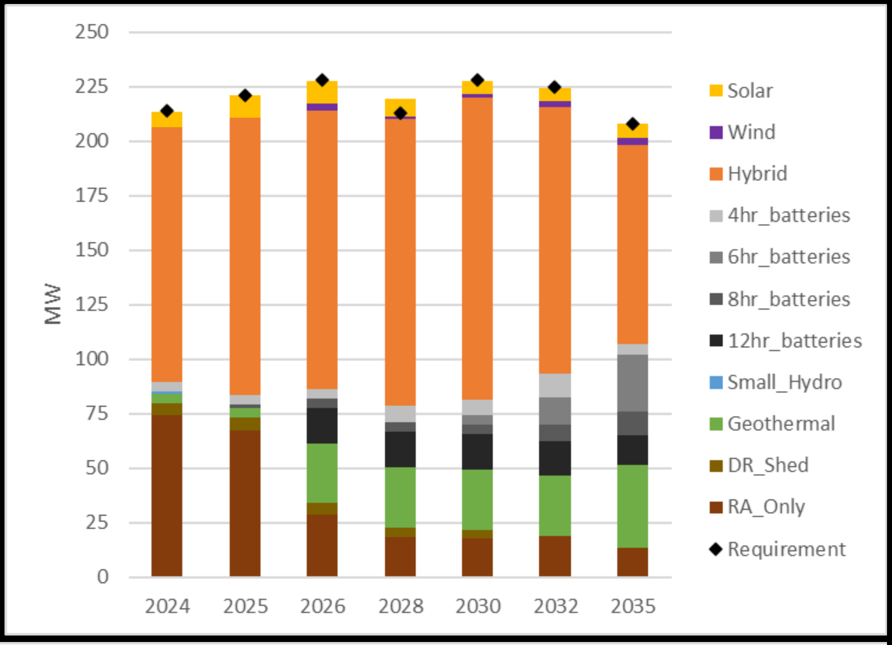
- Solar (stand-alone or hybrid) makes up 75% (65%) of contracted generation in 2030 (2035)
- Curtailment risk of VER resources only partially addressed in this analysis; additional analysis warranted
- Dashboard File:
    - MWh
        - Portfolio Summary I: columns V:AB
        - Portfolio Summary II: columns AB:AH

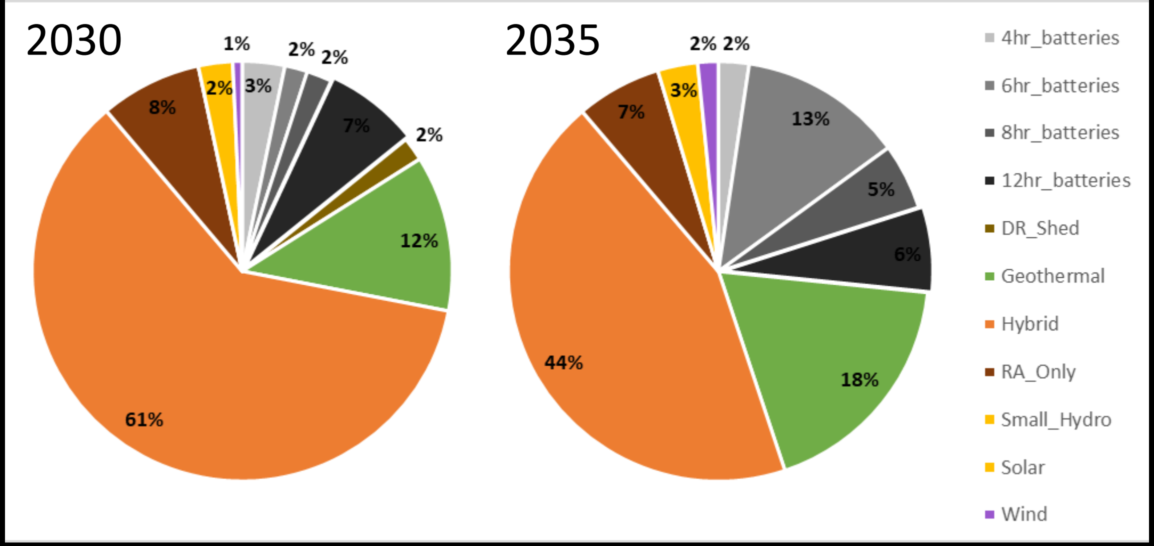


Scenario 1.A: ELCC – Resource Adequacy

First Principles Advisory

- Solar (stand-alone or hybrid) makes up 63% (47%) of firm capacity in 2030 (2035)
  - The more local capacity built into the portfolio, the less opportunity for other technologies types to be added
- Model calls on longer duration storage in part to benefit from larger ELCCs to satisfy the RA constraint
- Dashboard File:
  - Worktab: RA Constraint
  - Firm ELCC: columns N:T
  - Breakdown of ELCCs: columns AI:AL
    - Adjust cell AF1





Scenario 1.A: Hourly Dispatch (2024)

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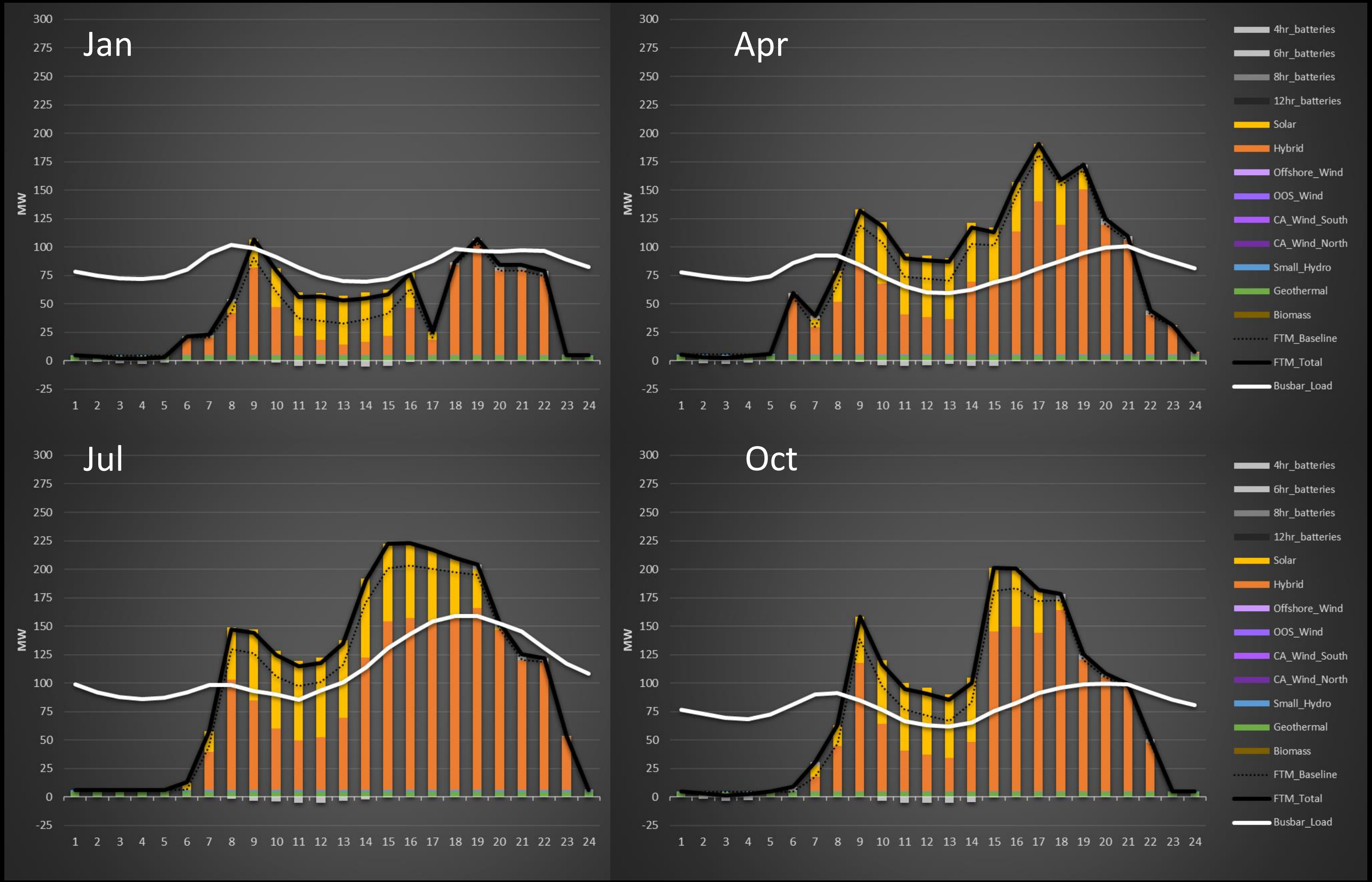
- The gap between the white line (busbar_load) and the black line (total_supply) represents market activity
  - Purchases are when load is greater than supply
  - Sales are when supply is greater than load

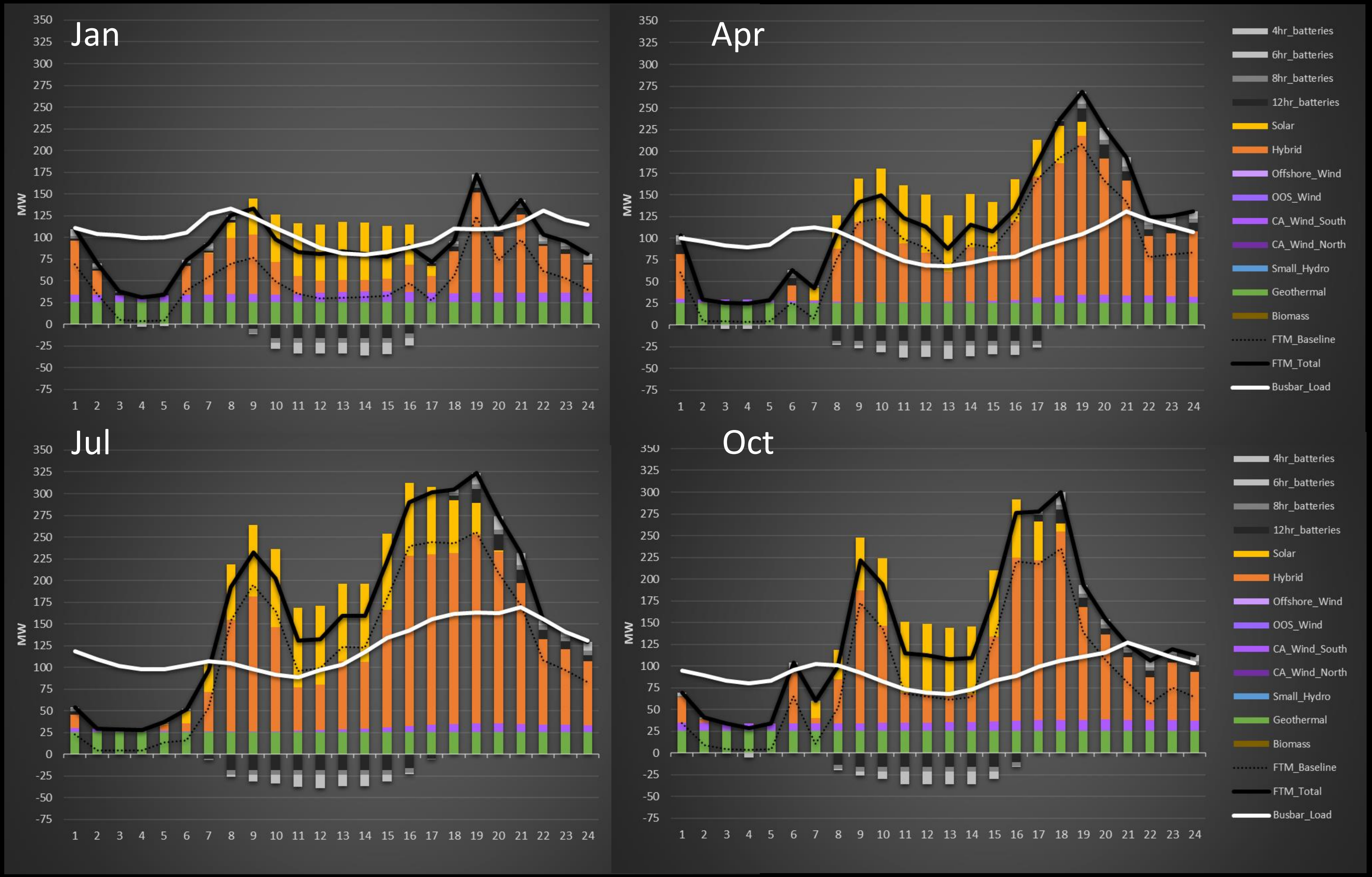
Dashboard File:

Worktab: dispatch_tech_total
Pivot Table: columns CP:DF
Note: be sure to refresh table when updating year of interest on meet_load_constraint tab



Scenario 1.A: Hourly Dispatch (2030)

- VCE is a net buy during the early morning hours throughout the year
- VCE is a net seller for the day and most of the evening in non-winter months
    - Max sales are during morning and afternoon peaks



Dashboard File:

Worktab: dispatch_tech_total
Pivot Table: columns CP:DF
Note: be sure to refresh table when updating year of interest on meet_load_constraint tab

Scenario 1.A: Hourly Dispatch (2035)

First Principles Advisory

- VCE is a net buyer during the early morning hours throughout the year
- VCE remains being a net seller but reduces its long position in the middle of the day with addition of more storage
- Excess sales unrealistic (see market constrained scenario)

Dashboard File:

Worktab: dispatch_tech_total
Pivot Table: columns CP:DF
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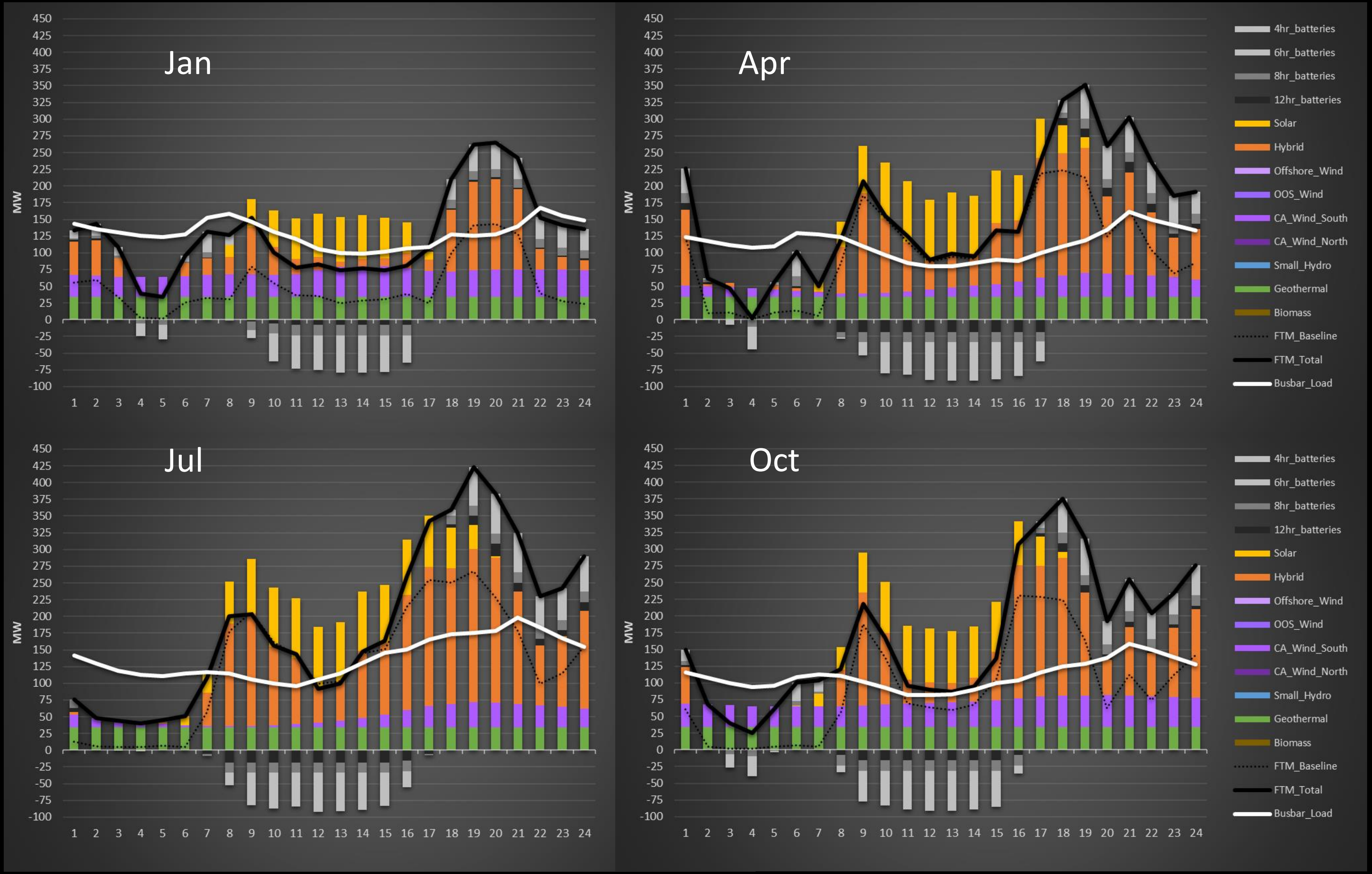
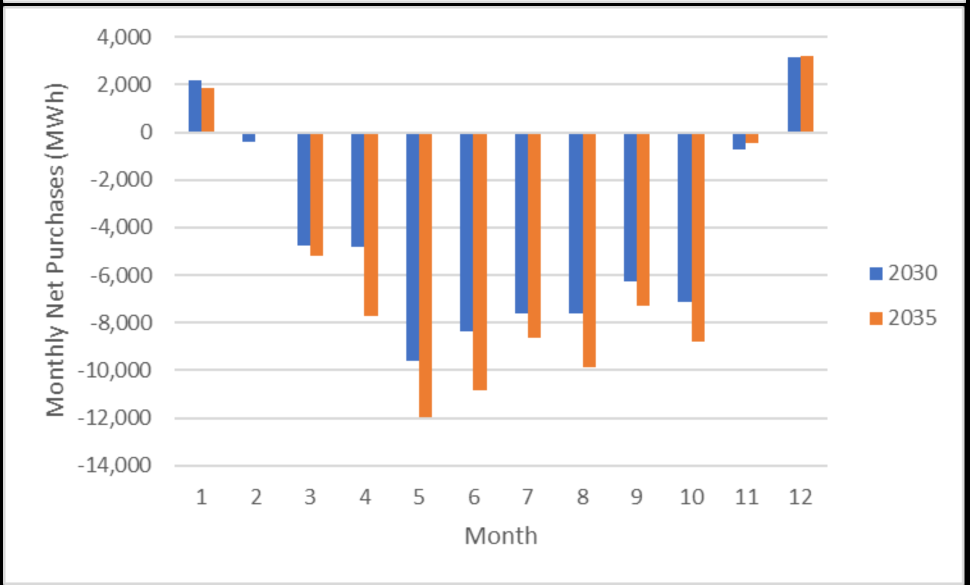


Scenario 1.A: Market Participation

First Principles Advisory

- In the unconstrained case, VCE converts from a net buy to a net seller in 2026 due to favorable unit economics of candidate projects reflected in the latest technology cost assumptions
- Winter months have the greatest dependency on the market
- Revision of regional modeling warranted to reflect the impacts of the IRA on candidate resources
- Dashboard File:
  - Worktab: market_participation
  - Annual Sales and Purchases: columns B:D
  - Annual sales revenue and purchase expense: columns: columns B:D



Scenario 1.A: Market Participation (cont)

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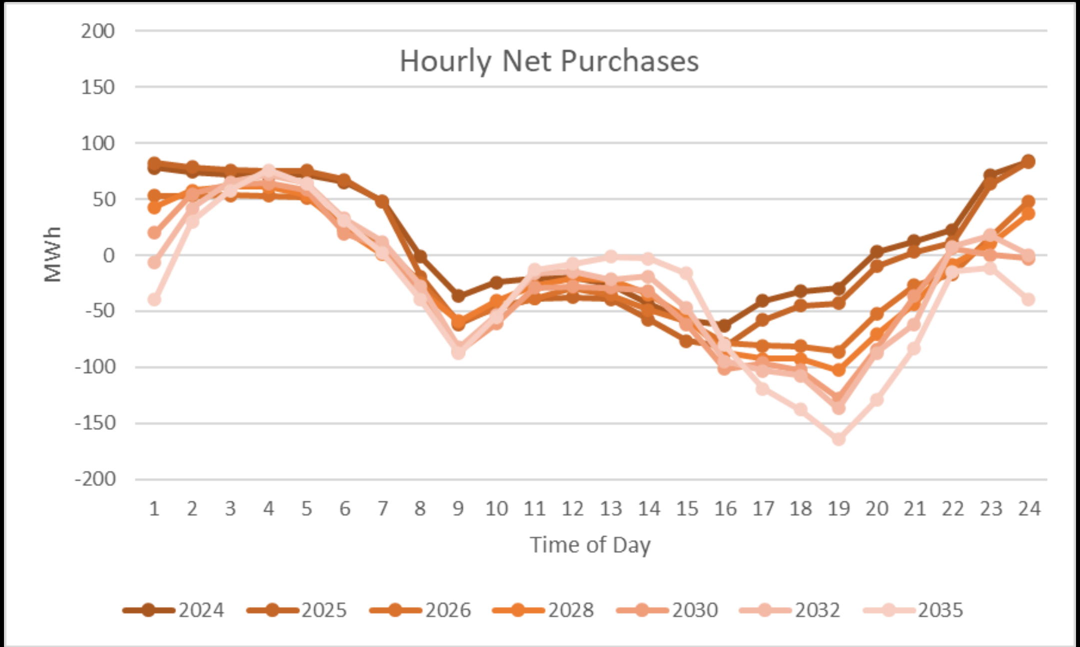
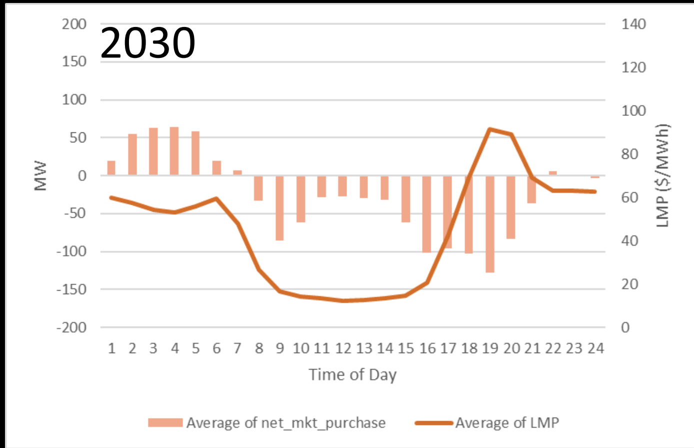
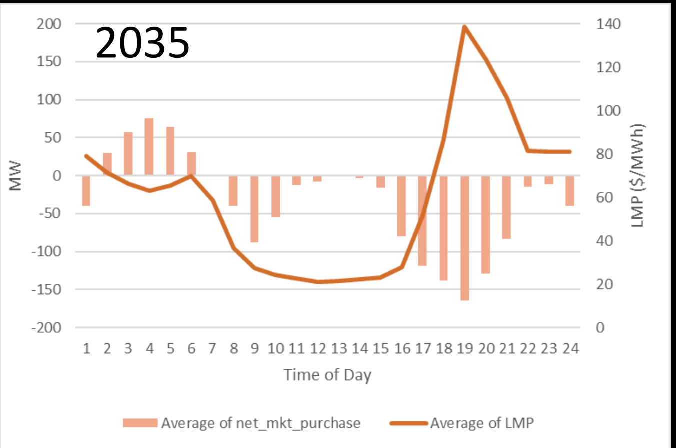
- VCE has open positions in the early morning hours across the entire planning horizon
  - VCE coverage over the later evening periods improves over time
- VCE has adequate coverage over the afternoon peak period across the entire planning horizon
- Average hourly open positions with the market differ greatly depending on the month
- VCE's long position in the middle of the day gradually improves over time
- Dashboard File:
  - Worktab: market_participation
  - Avg hourly net sales and LMPs by month-year: columns AY:AX
  - Avg hourly net sales by year: columns BE:BK



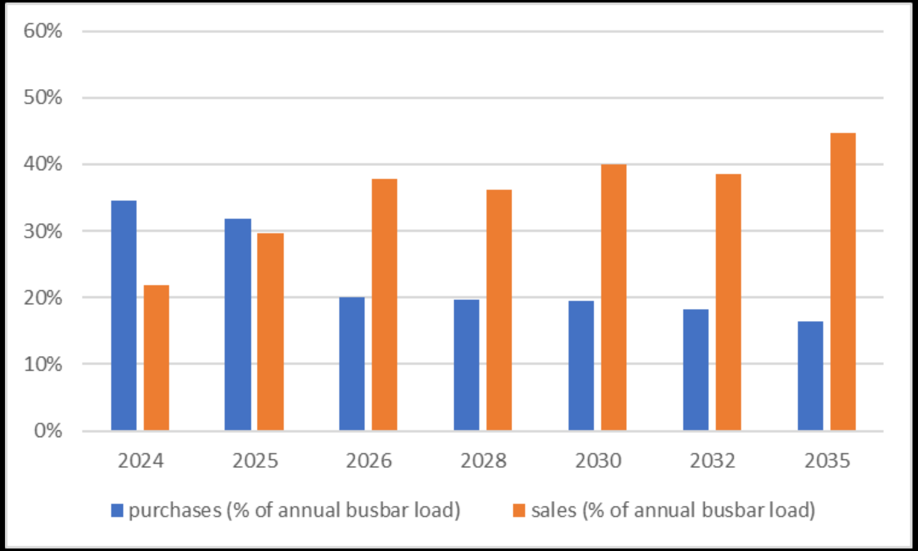




Scenario 1.A: Market Participation (cont)

First Principles Advisory

- The percentage of hours in the year in which VCE is short (i.e. purchasing energy from the market) decreases from 50% and levels off at around 37%
- The percentage of hours in the year in which VCE is long (i.e. sells energy into the market) ranges from 37%-48%
- Although VCE becomes less dependent on market purchases over time (as reflected by purchases as a % of annual load), the agency still gets ~15% of its load from the market in 2035
- VCE sales increase year over year primarily due to the favorable economics now being reflected in the IRA-adjusted technology cost curves, which makes most candidate resources NPV positive under current LMP pricing profiles*
- Dashboard File
    - Worktab: market participation
    - Columns: CM:CP



*Note: First Principles Advisory re-ran the optimization of VCE's portfolio to reflect the IRA-adjusted cost curves released by the CPUC in early June; these costs curves were not used to determine the PSP developed by the CPUC's RESOLVE model during the 2022 IRP cycle

Scenario 1.A: Costs

First Principles Advisory

- Total costs of the portfolio represent the aggregate of baseline, candidate and market
  - Baseline costs reflect fixed PPA charges for contracted projects
  - Candidate costs reflect forecasted PPA charges from incremental projects that would be added to the portfolio
  - Market reflects the net costs of load and total supply settling in the market
    - Note congestion is NOT accounted for in this analysis
  - Total costs are normalized to busbar load and shown in black (secondary y-axis)
- Net market transactions flips from a net cost to net benefit in 2026, likely reflecting an unrealistic assumption that VCE will be able to secure PPAs and favorable prices relative to other retail providers
  - The impact of this effect on the portfolio costs increases over time and should be addressed in subsequent studies
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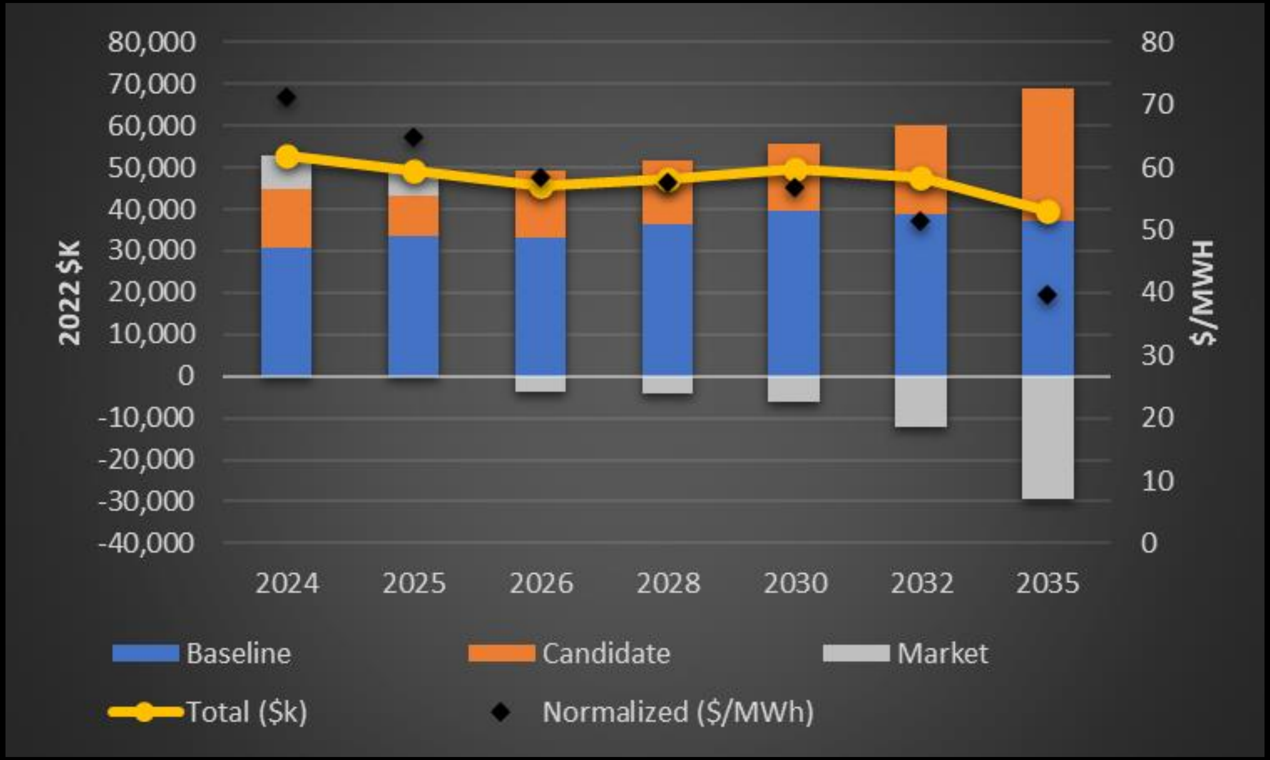
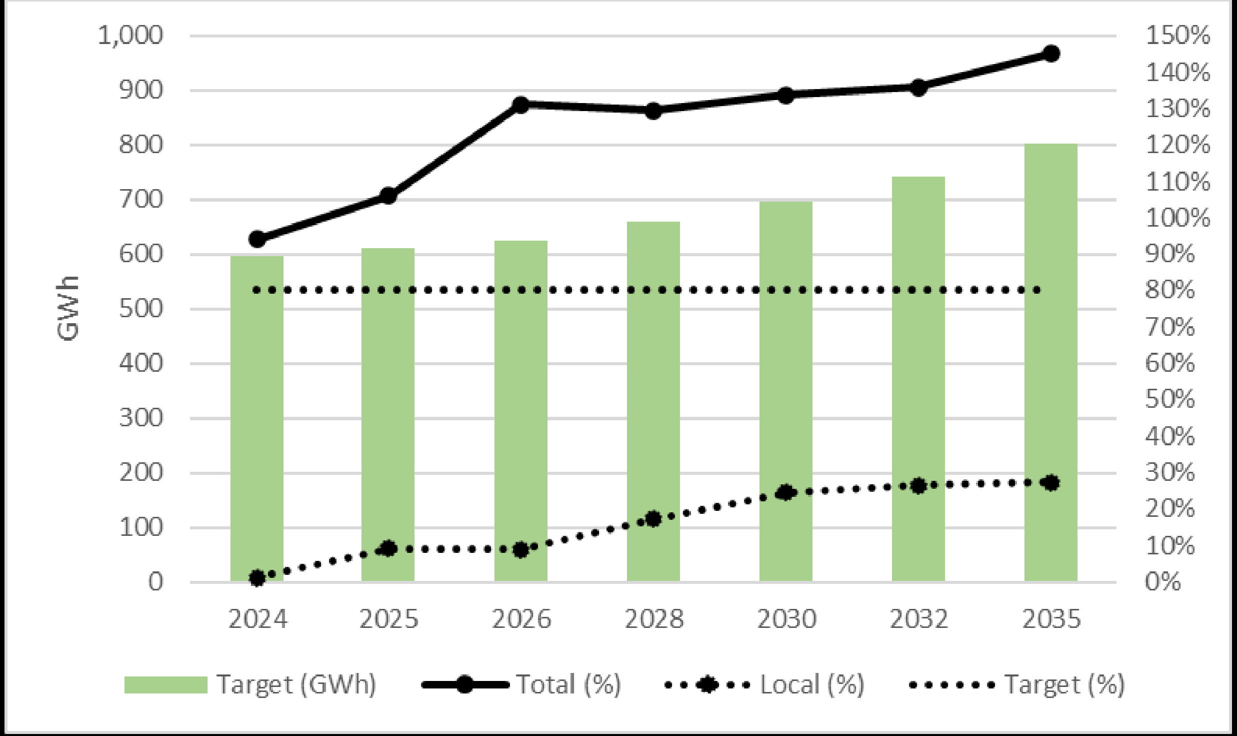
  - Worktab: NPV
  - Costs information: columns H:N



Scenario 1.A: Renewable Portfolio Standard (RPS)

First Principles Advisory

- For the baseline case of 80% RPS by 2030, there is no incremental cost in the model to satisfy this constraint
  - The 100% by 2030 constraint in scenario 1.B also doesn't bind
- VCE far exceeds its total RPS target in 2030 and beyond
  - Additional projects are added to the portfolio in order to satisfy the RA constraint
- The model is constrained to ensure that a minimum of 25% of the RPS constraint is met with generation from local projects
- Dashboard File:
  - Worktab: RPS
  - Costs information: columns P:V

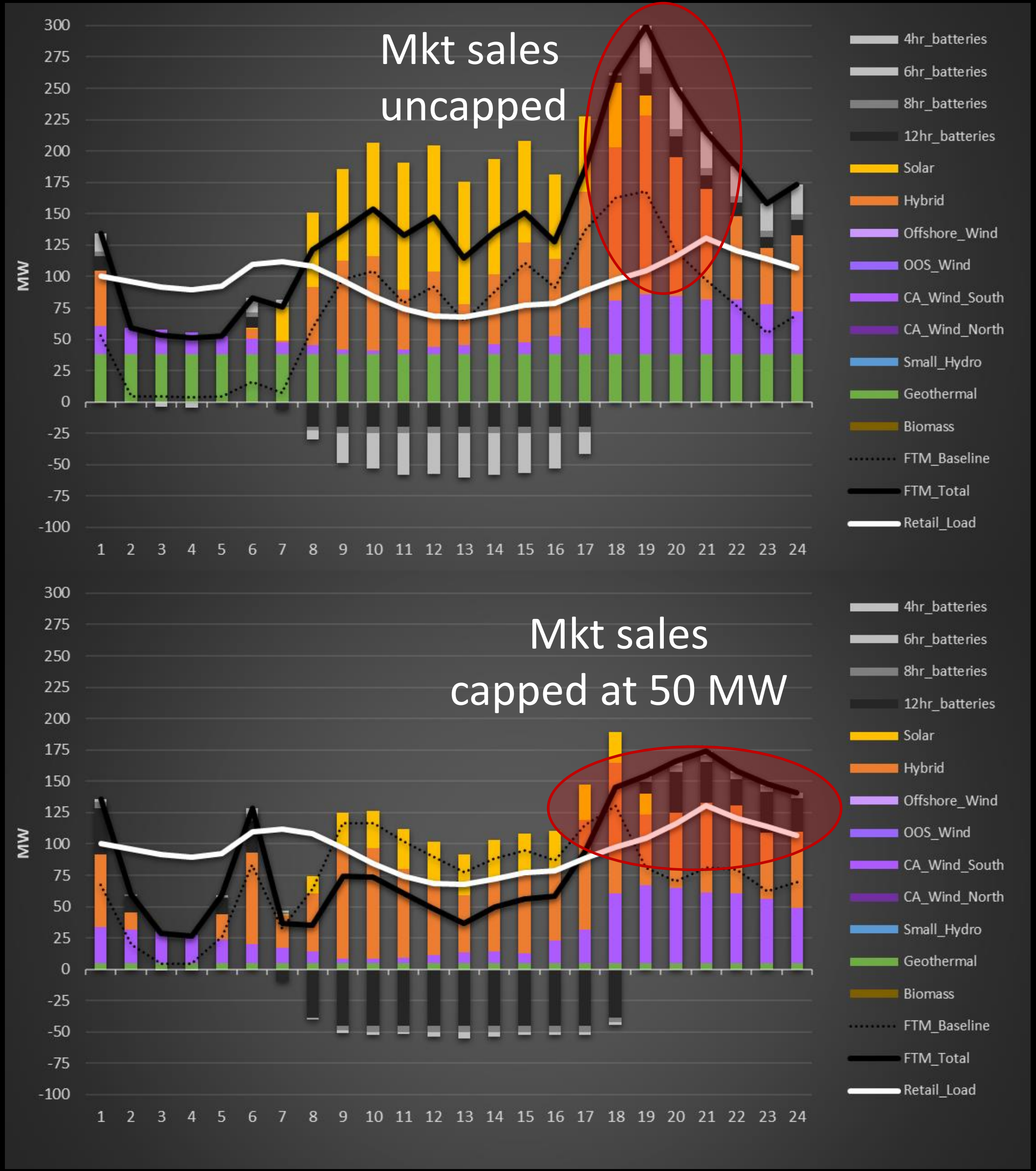


Sensitivity Case: Capped Market Transactions

Sensitivity Case: Market Transactions Policy

First Principles Advisory

- Given VCE’s large concentration in hybrid projects, the agency will be in a position to engage in extensive market sales throughout most of the year
- VCE should define a risk management policy that defines the maximum allowed market purchases and sales in any given hour or slice of day
- Without this risk management policy defined, future portfolio optimization exercises will likely result in procurement decisions that are not in alignment with prudent scheduling practices
- There is significant variations in costs depending on what gets assumed in the model



Financial Summary: Market Transactions

First Principles Advisory

Index	Natural Gas Price	RPS 2030 Target	Local RPS Requirement	Market Policy	Local Hybrid Capacity (MW)	2024-2035 NPV (2022 $M)	Delta (2022 $M)
1.A	P50	80%	25%	Uncapped	65	619.6	0
1.B	P50	100%	25%	Uncappe		643.1	23.5
1.C	P50	100%	n/a	Uncappe		586.1	-33.4
3.A	P50	80%	25%	Capped (50 MW)	65	705.4	0
3.B	P50	100%	25%	Capped (50 MW)	84	719.0	13.5
3.C	P50	100%	n/a	Capped (50 MW)	0	686.1	-19.4

+$85.8M in costs when capping sales

- When capping market sales to 50 MW in any given hour, the cost premium in increasing VCE's 2030 RPS target and keeping the 25% local requirement results in an additional charge of $13.5M in present value relative to VCE's current policy (e.g., 80% RPS with a 25% carve out)
- If VCE increases their 2030 RPS target to 100% but doesn't require any additional local projects results in a cost savings of $19.4M
- The NPV of the base case increases by $85.8M in scenario 3, an increase of 13%. This reflects the importance of VCE defining its risk management policy for how it wants to handle its net exposure with the market

Procurement Implications

Procurement Recommendations (redacted)

First Principles Advisory

Technology Breakeven Prices (redacted)

First Principles Advisory

- Breakeven price is the levelized PPA price that results in an NPV of zero based on the levelized benefits of energy and RA*
- Listed prices are the average breakevens for 2024-2026
- Dashboard File:
  - Worktab: Breakeven Prices
  - Storage: Column A; rows 123-140
  - Non-Storage: Column N; rows 178-214

*Breakeven prices do not include any benefit assumed from PCC1 attributes

Potential Next Steps

Topics for Additional Investigation

First Principles Advisory

- Incorporate Slice-of-Day (SOD) into optimization logic used by the model
  - This study assumed ELCC values, per the methodology utilized in Commission’s IRP cycle
- Conduct an all-source solicitation (to collect current market prices for PPAs) and re-optimize portfolio with these costs to determine least cost solution to fill VCE’s near term open position
- Optimize the portfolio using nodal prices rather than systemwide zonal prices
  - This feature will provide a more accurate assessment of curtailment volumes for both baseline and candidate resources
- Direct integration of GHG accounting; 24/7 GHG-free modeling
  - Integrate CPUC’s Clean System Power GHG accounting methodology (or other logic) into the model to estimate what the incremental costs would be for VCE
- Develop Stochastic Optimization
  - This functionality for the handling of uncertainty in key variables within the model when selecting candidate resources
  - Currently the model conducts deterministic studies of multiple scenarios to estimate the impacts of uncertainty in future conditions

Key Modeling Inputs / Methodologies

VCE Load

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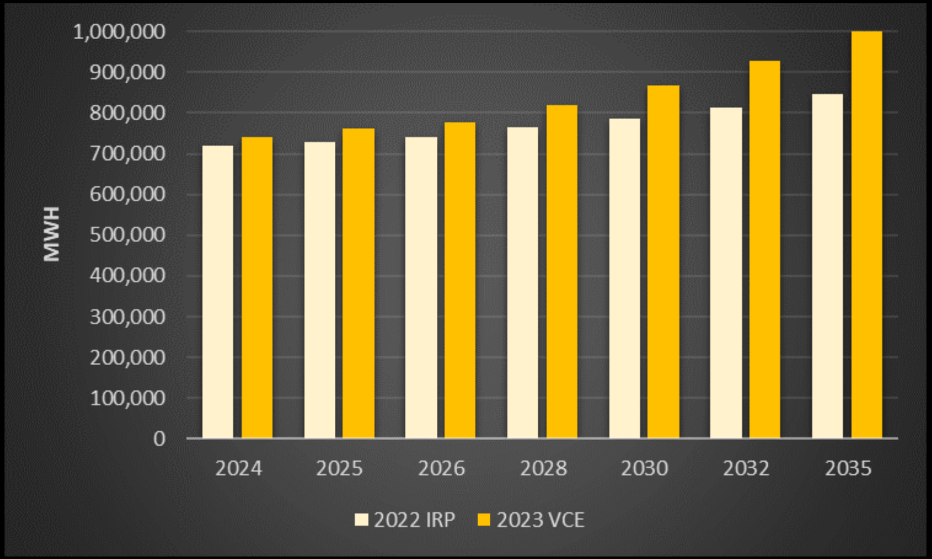
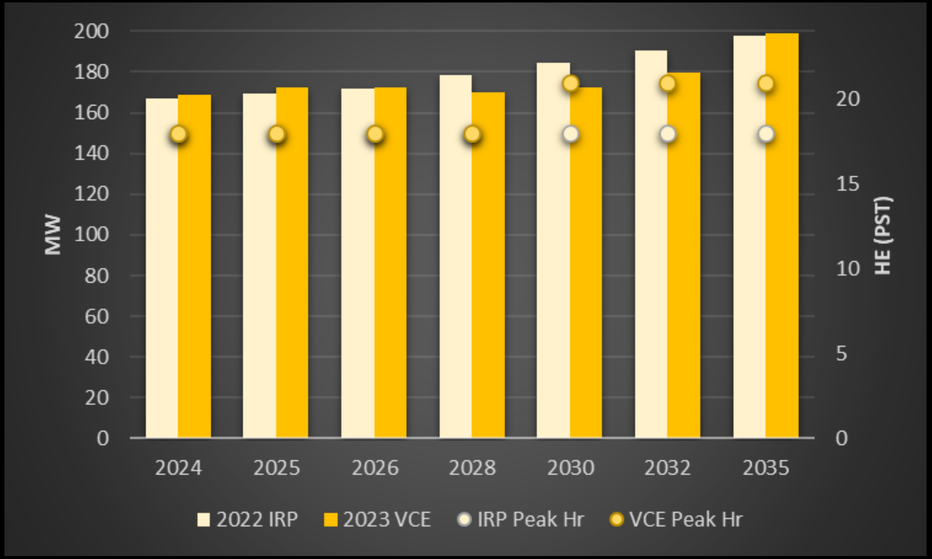
- TEA provided VCE and First Principles Advisory with an updated net retail forecast across the entire planning horizon of 2024-2035
    - Forecast is NET of BTM solar production
- Updated forecast reflects higher (35% vs 18%) load growth across the planning horizon of 2024-2035; this is primarily due to building and transportation electrification
    - Comparatively, the increase in annual peak demand is 18%
- The implicit assumption in the forecast is that VCE will avoid sharp increases in its peak demand either passively (from natural customer behavior) or actively (from customer programs)
    - Minimizing increases in peak demand is critical is critical because this impacts the amount of RA VCE will be responsible for procuring
    - The RA constraint is the most binding constraint in the model (i.e., this is what forces VCE to go out and contract for additional resources to be in compliance)

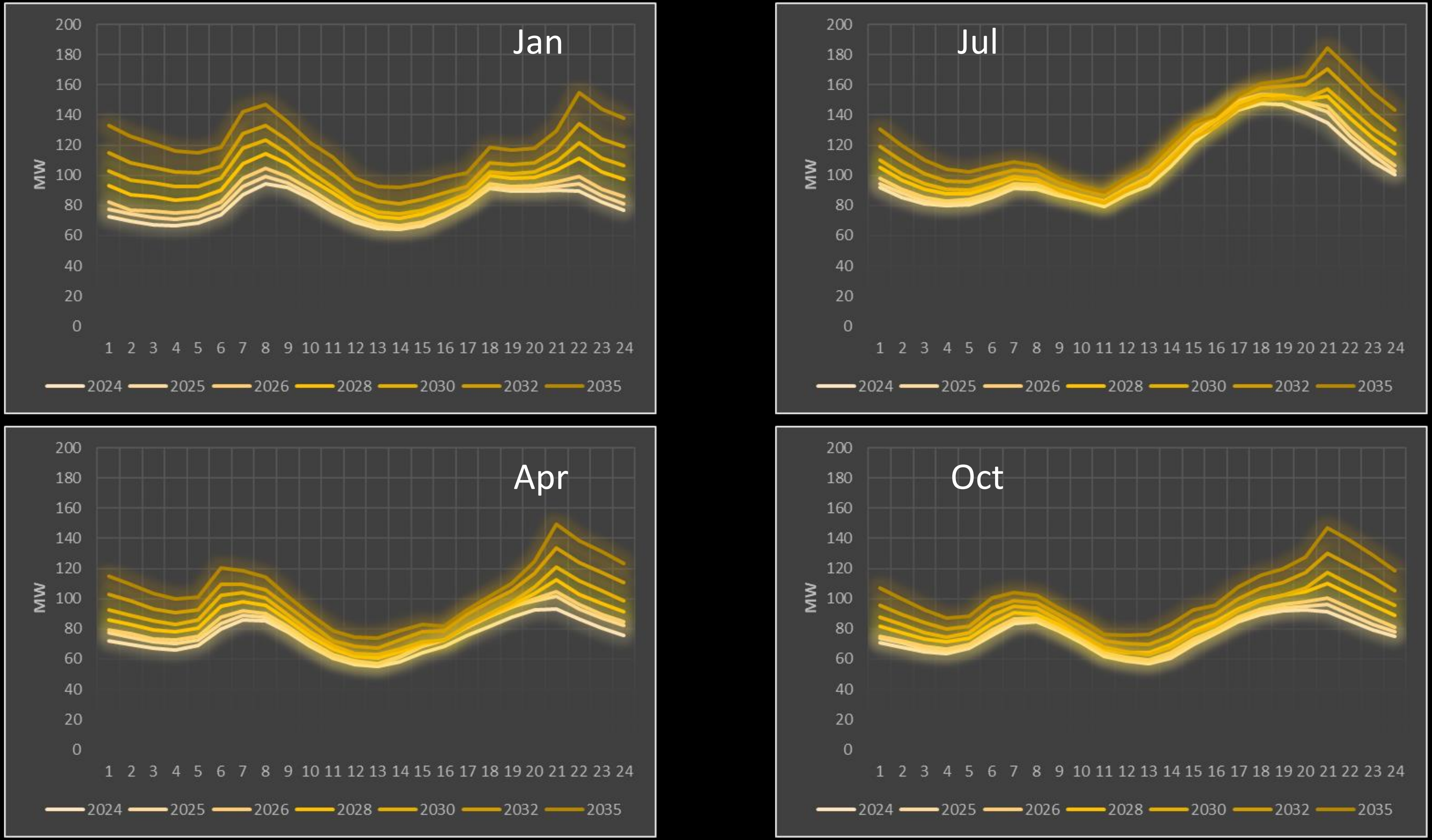




*Note: load in dashboard file represents busbar load (i.e. retail load grossed up for T&D losses)

VCE Load Profile

First Principles Advisory



- Customer programs / rate design will be key drivers in shaping VCE's load shape
- Further out on the horizon, winter peak morning leads begin to present similar risks summer peak afternoon loads

RA Forecast (redacted)

First Principles Advisory

NG Profile (redacted)

- Customer programs / rate design will be key drivers in shaping VCE's load shape
- Further out on the horizon, winter peak morning leads begin to present similar risks summer peak afternoon loads

Plexos LMP Profiles (P50) (redacted)

First Principles Advisory

Jan

Jul

Apr

Oct

- Prices in the late evening / early morning increase
- Even with increasing load, prices in the middle of remain suppressed

Plexos LMP Profiles (P95) (redacted)

First Principles Advisory

Jan

Jul

Apr

Oct

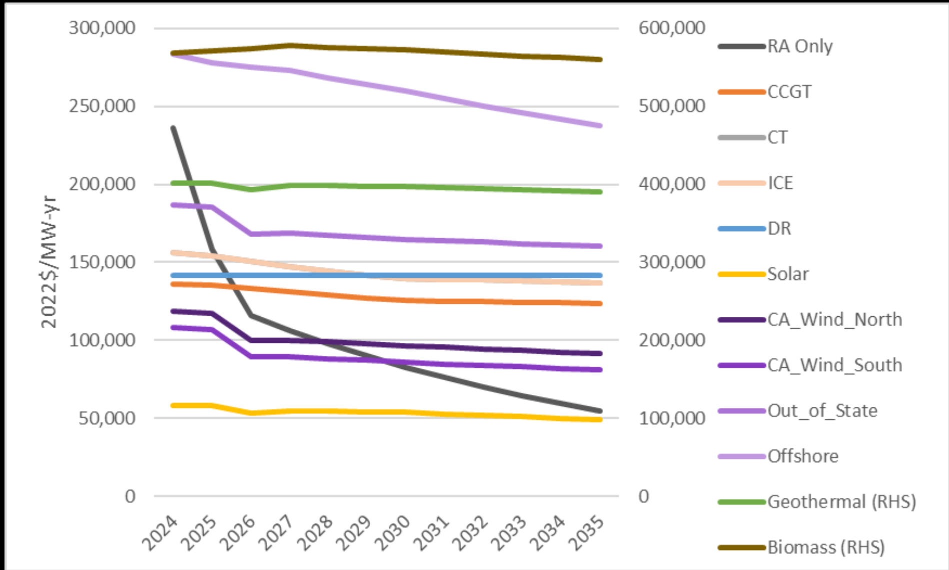
- Prices in the middle of the day are elevated in the winter months but muted in remaining parts of the year

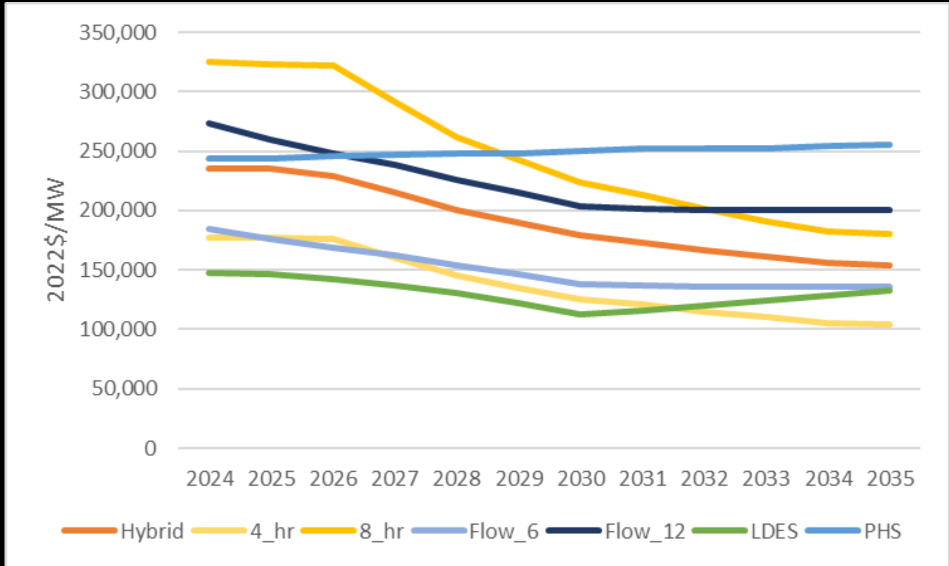
Technology Cost Curves

- First Principles Advisory has taken the cost curves from the CPUC's latest Inputs and Assumptions document which can be found here.
- The impacts of the Inflation Reduction Act (IRA) has been applied to all resource types through 2048
- The CPUC applied additional cost modifications to solar, onshore wind, and Li-ion batteries to reflect contemporaneous stressed market conditions
- First Principles Advisory assumed an additional 20% of tax incentives for Li-Ion storage (bringing the ITC up to 50%) for the low-cost battery cost curve

Technology Cost Curves: Overall

- Total levelized fixed costs include both CAPX and fixed O&M charges
- IRA has increased the cost competitiveness of clean, firm resources (e.g., geothermal, biomass, and non li-ion based storage)
- RA Only curve represents internal forecast of annual price for RA only contracts



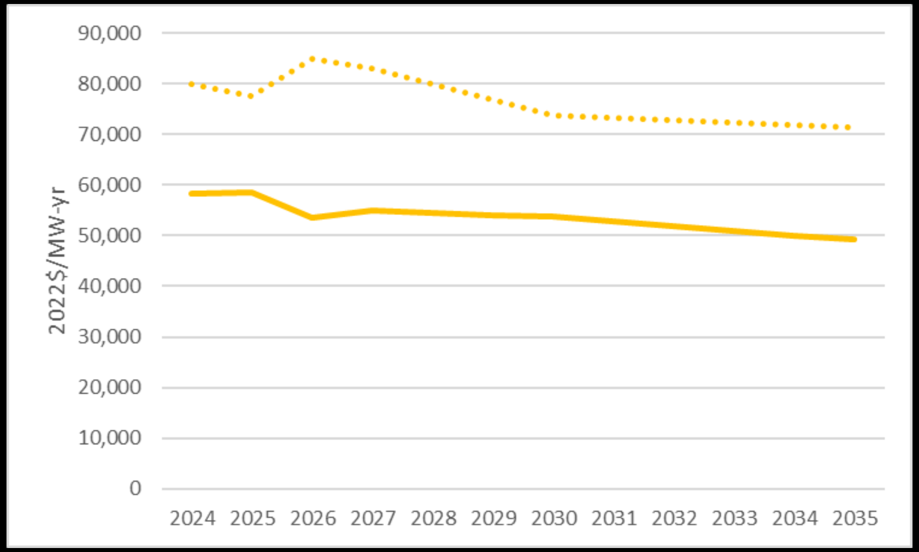


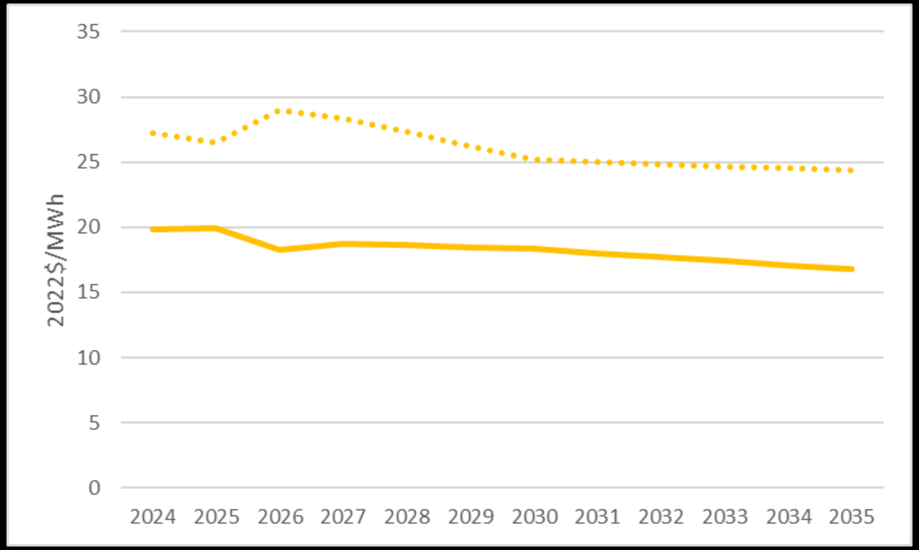
Updated

Original

Technology Cost Curves: Solar

- IRA enables solar project to now also have access to the Production Tax Credit (PTC) which is a tax credit of $25/MWh
- Given the more favorable economics of the PTC over the Investment Tax Credit (ITC), the prevailing notion is that developers will opt for the PTC
- CPUC assumes developers meet prevailing wage and apprenticeship rules to qualify for “Bonus” incentive



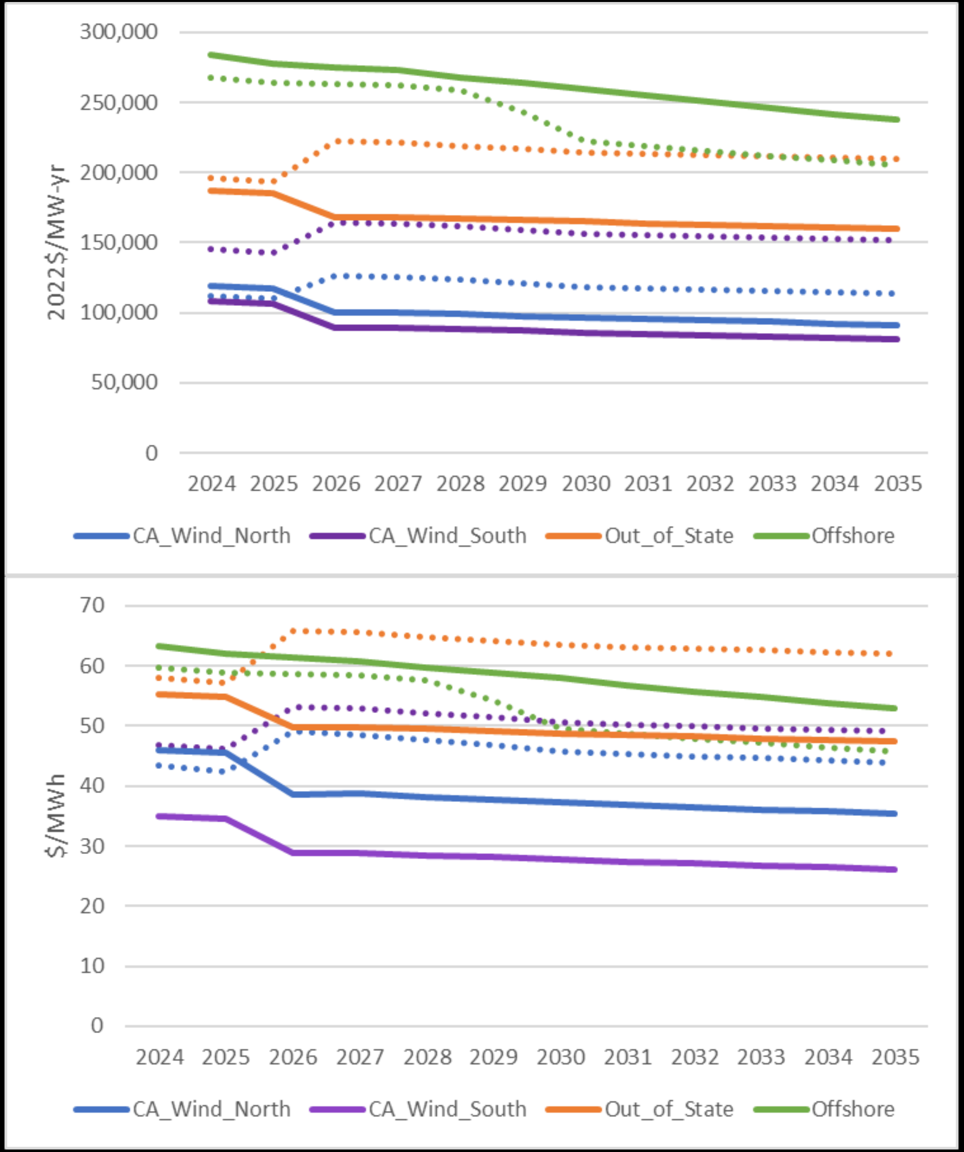


Updated

Original

Technology Cost Curves: Wind

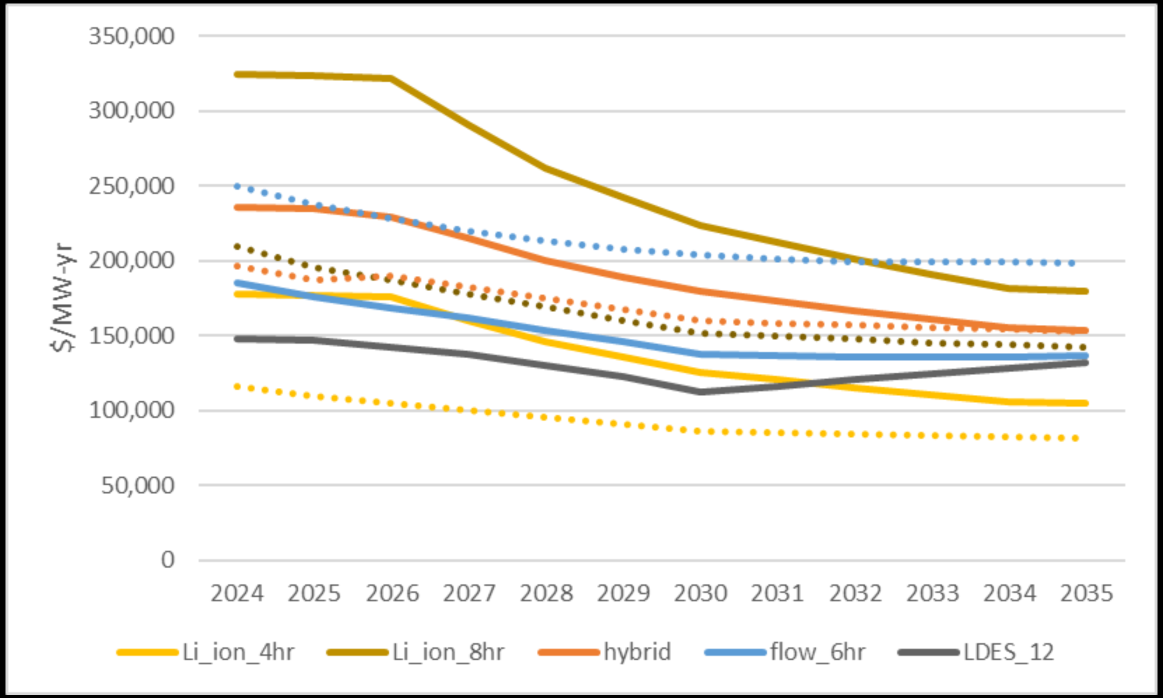
- IRA extended availability of PTC, which was originally scheduled to expire in 2026 for onshore wind
- CPUC assumes offshore wind will take ITC; thus no changes from IRA until post 2035; CPUC also increased the cost slightly from last IRP cycle
- CPUC assumes developers meet prevailing wage and apprenticeship rules to qualify for “Bonus” incentive



Technology Cost Curves: Storage

Updated
Original

- Although stand-alone storage now qualifies for ITC, the CPUC adjustments to account for strained market conditions for li-ion storage result in an overall cost increase for lithium-based storage projects
- Flow batteries see a substantive affect from the IRA tax incentives as does long duration energy storage (LDES) technology, which represents iron air batteries
- CPUC assumes developers meet prevailing wage and apprenticeship rules to qualify for "Bonus" incentive

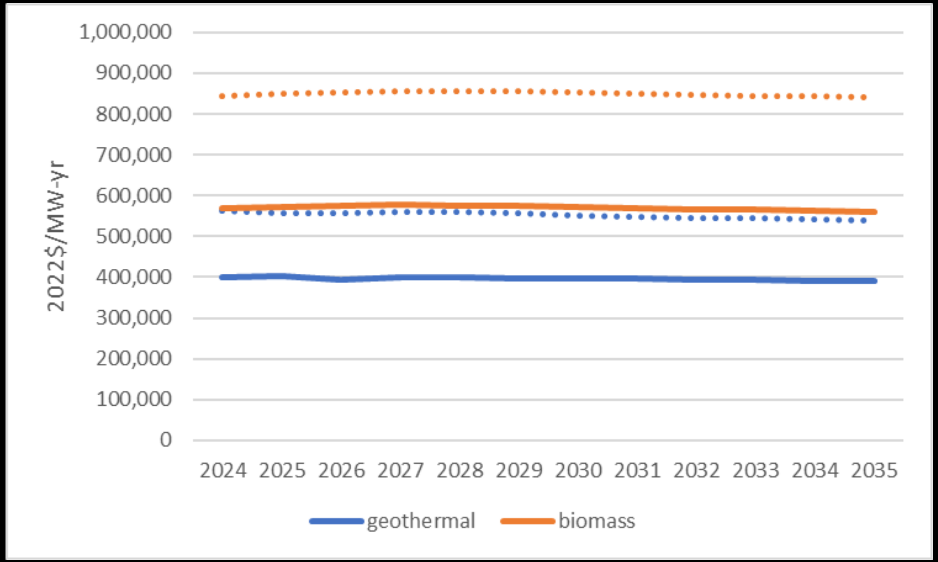


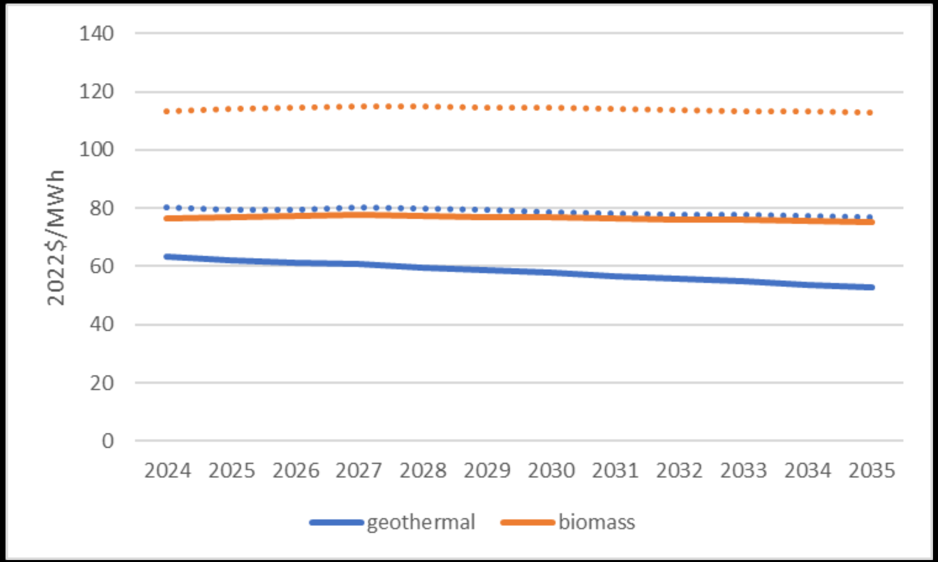
Updated

Original

Technology Cost Curves: Clean, Firm

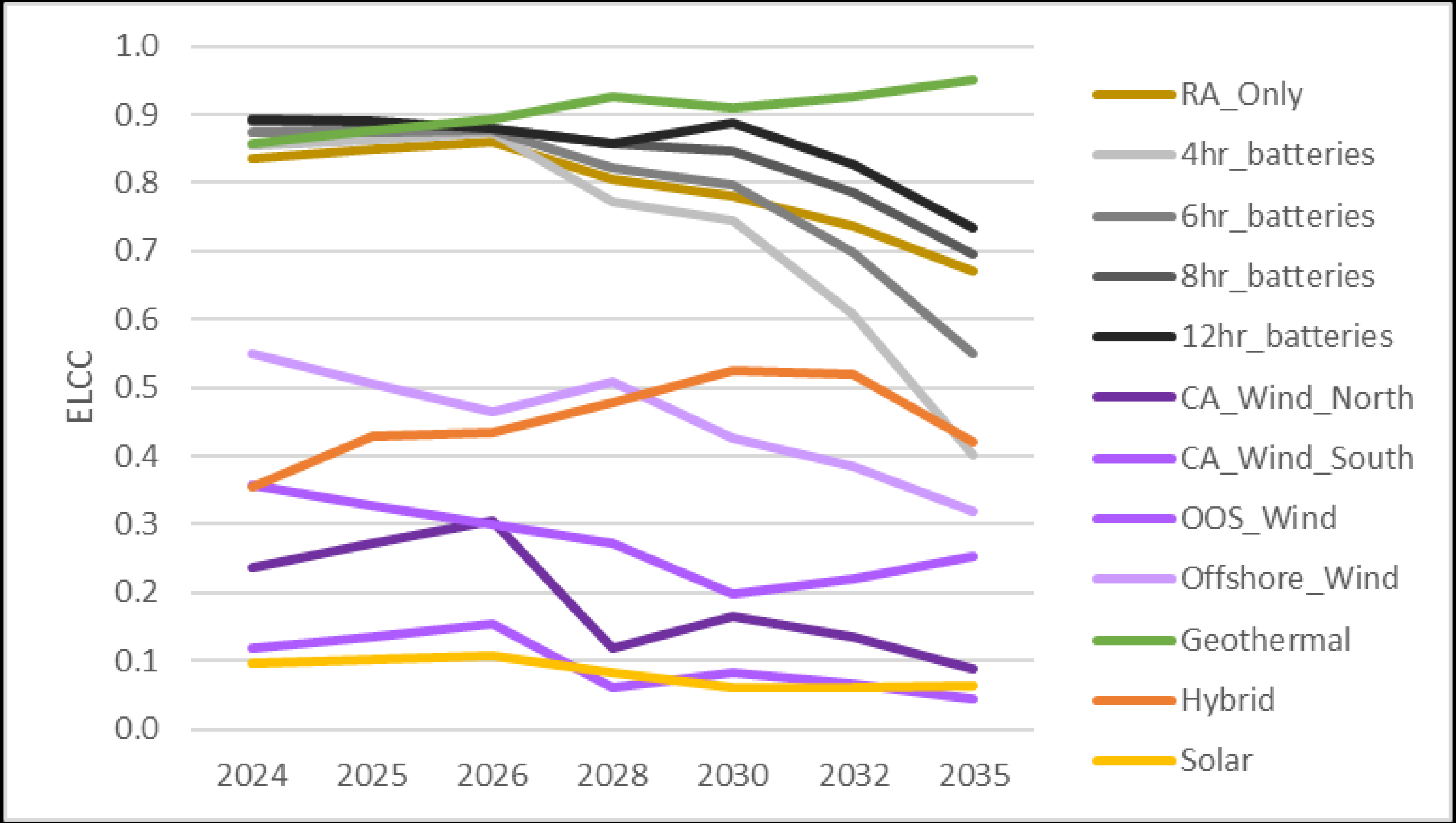
- Under the IRA, geothermal and biomass now qualify for the 30% ITC, previously this was 10%
- CPUC assumes developers meet prevailing wage and apprenticeship rules to qualify for “Bonus” incentive





ELCC Factors

First Principles Advisory



Modeling Process

Production Cost Modeling (Plexos)

- IRP Buildout (IRP)
- NG Forecast (TEA)
- GHG Forecast (CEC)
- PCC1 Forecast (TEA)
- Adjusted Net Load / Multiple Weather Years (FPA/CPUC/CEC)

Portfolio Optimization (GridPath)

- LMP Profiles (Plexos)
- RA Forecast (TEA)
- PCC1 Forecast (TEA)
- VCE Policy (VCE)

- Step 1: Generate regional WECC prices for 2024, 2026, 2028, 2030, 2032, and 2035 using zonal Plexos model based on CalCCA and First Principles Advisory databases
- Step 2: Along with LMP profiles, apply other market forecasts to VCE portfolio to identify optimal buildout of incremental contracts to determine least cost solution that satisfies the agencies policy goals and regulatory requirements

Key Modeling Assumptions

First Principles Advisory

- Typical Week temporal resolution
  - 168 continuous hours selected for each calendar month
  - 2016 dispatch intervals in each calendar year
- 3 adjusted net load weather years modeled in Plexos for each calendar year
  - High, med, low
  - Average of the 3 runs are applied downstream
- All dollar values are reported in real terms (2022$)
- All time periods are listed in pacific standard time (PST)

GridPath vs Match

Similarities
Open-source
Month-Hour; Day of Week Dispatch
Stochastic weather inputs
Deterministic
Scenario analysis

Differences		
Topic	VCE	PCE
Fundamental Model	Plexos WECC zonal db	Ascend's PowerSIMM*
Planning Horizon	2024-2035	2025
Functionality	CEM, PCM, PEM	PEM
Support / Development	GridPath is supported by 3rd party (Blue Marble)	MATCH is unsupported
VER profiles	n/a	Generates profiles
Primary objective function	Dispatching units in most economic manner	Matching hourly supply to load
RPS Policy	Annual	24/7/365