Utah Schedule 37 Technical Conference

August 31, 2017

Recent Schedule 38 History - Orders

- **Docket 12-035-100 (*Aug. 16, 2013*)**
  - Proxy-PDDRR method approved for determining avoided costs for all QFs larger than three megawatts
    - Deferral of “like” cost-effective renewable resources
    - Deferral of thermal resources, if the IRP planned resources do not include “like” renewable resources.
    - Approved capacity contribution values for wind and solar
    - Approved wind and solar integration costs
  - RECs retained by QFs, unless provided for otherwise by a negotiated contract
- **Docket 14-035-140**
  - *June 9, 2015*: approval of settlement establishing:
    - PPA negotiation milestones
    - Potential QF queue management procedures
    - New or updated avoided cost modeling assumptions will be identified and explained in quarterly compliance filings.
  - *June 26, 2015*: approval of updated wind and solar capacity contribution values
- **Docket 15-035-53 (*Jan. 7, 2016*)**
  - Maximum QF term length reduced from twenty years to fifteen years

Recent Schedule 38 History

Quarterly Compliance Filings – non-routine updates

- **Docket 14-035-40**
  - 2014.Q2: Removal of carbon tax from official forward price curve (OFPC)
  - 2014.Q2: Addition of “Clover” load bubble in central Utah
  - 2014.Q3: OFPC includes regional compliance with §111(d) of Clean Air Act
  - 2014.Q3: Wind integration cost update
- **Docket 15-035-56**
  - 2015.Q2: Solar degradation
  - 2015.Q2: Post-2028 Wyoming transmission rights
  - 2015.Q2: Reserve shortage costs
  - 2015.Q2: Wind integration reserve shortage costs

Recent Schedule 38 History

Quarterly Compliance Filings – non-routine updates

- **Docket 16-035-29**
  - No non-routine updates identified
- **Docket 17-035-37**
  - 2017.Q1: REC Ownership: Company entitled to REC’s during that portion of a QF’s term that it receives capacity payments based on deferral of a renewable resource
  - 2017.Q1: Avoided cost pricing beyond end of preferred portfolio (currently 2036) to be calculated by escalating final year values at inflation.

Aeolus-Bridger/Anticline Transmission Alternatives

- The existing transmission system in eastern WY is constrained, with more generation resources than load and transmission transfer capability
  - Additional generation cannot be connected to the existing system
  - During outages of system elements in the 230kV transmission system there are voltage stability issues and additional constraints on the system.
- Since 2013 the Company has completed several important projects to enhance the transmission system in southeast Wyoming, including:
  - Dynamic line rating of the Miners (Standpipe)-Platte 230 kV line (2013)
  - Southern Wyoming Voltage Control Scheme, which coordinated wind generation reactive output to stabilize local area voltages (2012-2015), and
  - Construction of the Standpipe substation and (60 MVAr) synchronous condenser for voltage control (2016).
- PacifiCorp transmission planning completed studies for the proposed configuration utilizing a single circuit 500kV line.
  - Path ratings for 500kV line have been reviewed and were accepted in 2011
  - 500kV line has been permitted and received a Record of Decision.
  - 500kV line design has been reviewed to lower projected costs – utilizing experience from previous Energy Gateway segments
- Path rating studies and detailed cost comparisons have not been conducted for lower voltage alternatives.
- At a high level, the cost of a new 230kV line along with the existing system improvements would be close to the cost of the 500kV line but without the same level of transfer capacity increase or reliability improvements.

UT QFs vs 2021 Wind and Transmission

Can 240MW of UT QFs located near load defer 240MW of the 1100MW of wind and 240 MW of transmission capacity?

- Transmission upgrades have discrete sizes (e.g. 230kV, 345kV, 500kV)
- Lower voltage options have only somewhat smaller costs – so cost savings on the last 240MW of transmission, assuming that increment is even possible, are expected to be low
- As shown later on:
  - After accounting for the PTC, the cost of the 2021 wind resources is very low.
  - UT QFs don't need to defer the 2021 wind and transmission to provide significant value for customers – they provide <u>more</u> value by avoiding fuel costs, market purchases, and future resources in the preferred portfolio that are more expensive than the 2021 wind.

2021 Wind and Transmission Alternatives

- PacifiCorp has not identified a replacement preferred portfolio.
- The best performing portfolio in the 2017 IRP that didn't include Gateway D2 was FS-REP, with a risk-adjusted cost that was $150M higher than the preferred portfolio (see Table 8.15).
- After grossing up for state and federal income taxes, a PTC is worth approximately $39/MWh in 2017$ on a revenue requirement basis.
- Dividing the portfolio cost differential by the value of a PTC provides an estimate of the lost PTCs before FS-REP would be lower cost.
    - $150M / $39/MWh = 3.8M MWh
- With a 41.2% c.f., 1100 MW of the 2021 wind produces ~4.0M MWh per year.
- 3.8M MWh of lost PTCs is roughly 10% of the 2021 wind over its ten years of PTC eligibility.
- If 10% lost PTCs were anticipated, adding less wind capacity would reduce the lost PTCs, and would avoid significant capital costs on the wind resources, which would improve the portfolio's performance – identifying the right amount of wind to add will be key.

Figure 1: Avoided Cost Assuming Deferral of IRP Wind Resources, by Resource Type, with Existing Resource Capacity Position

- PDDRR, assuming deferral of capacity-equivalent amounts of 2021 Wyoming wind resources
- PTC levelized over proxy resource asset life (30 years)
- Wyoming wind energy value increases significantly in 2028, due to retirement of Dave Johnston, avoided costs drop as a result.
- Variation by resource type reflects capacity to energy ratios relative to 2021 wind

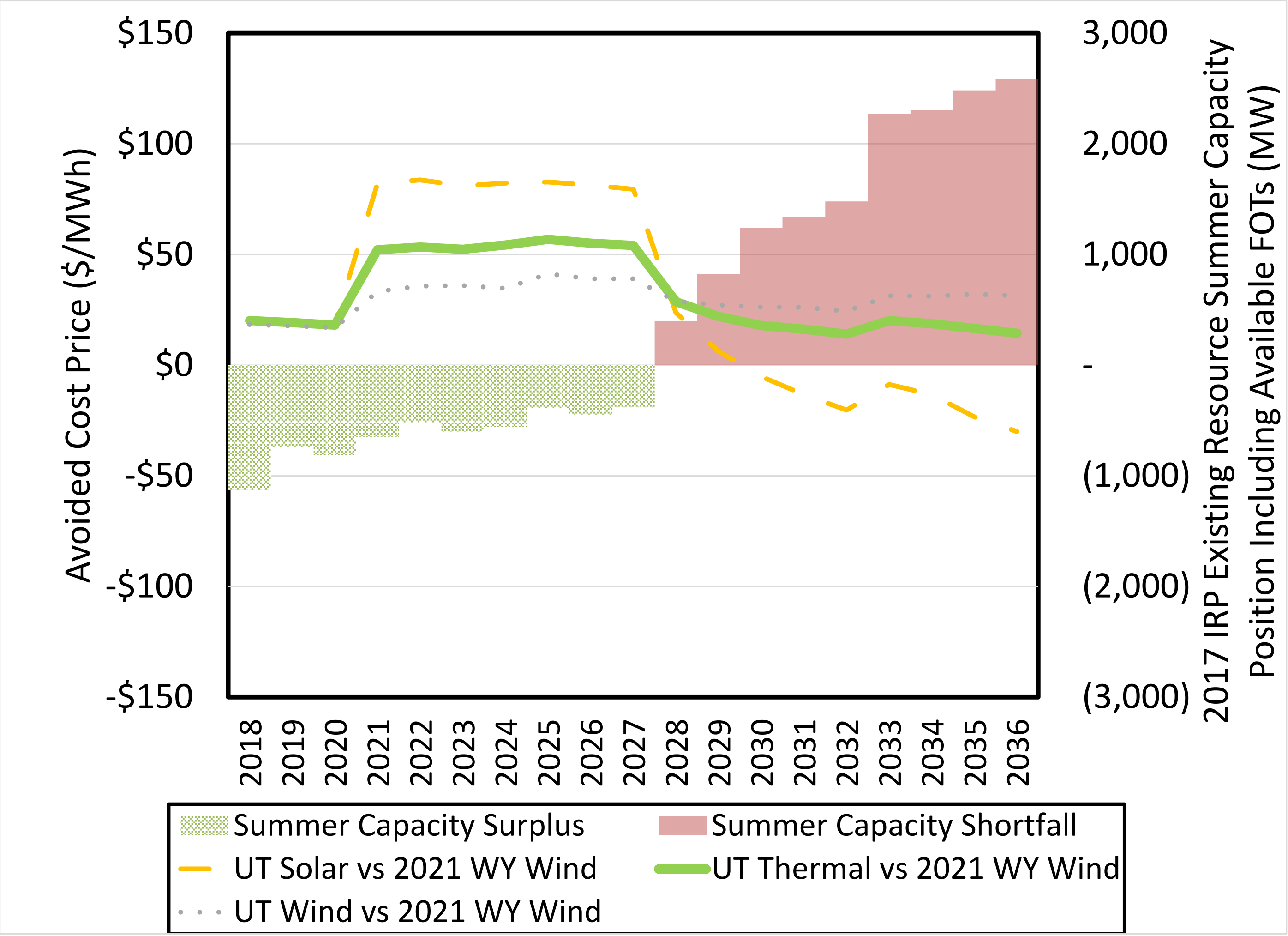


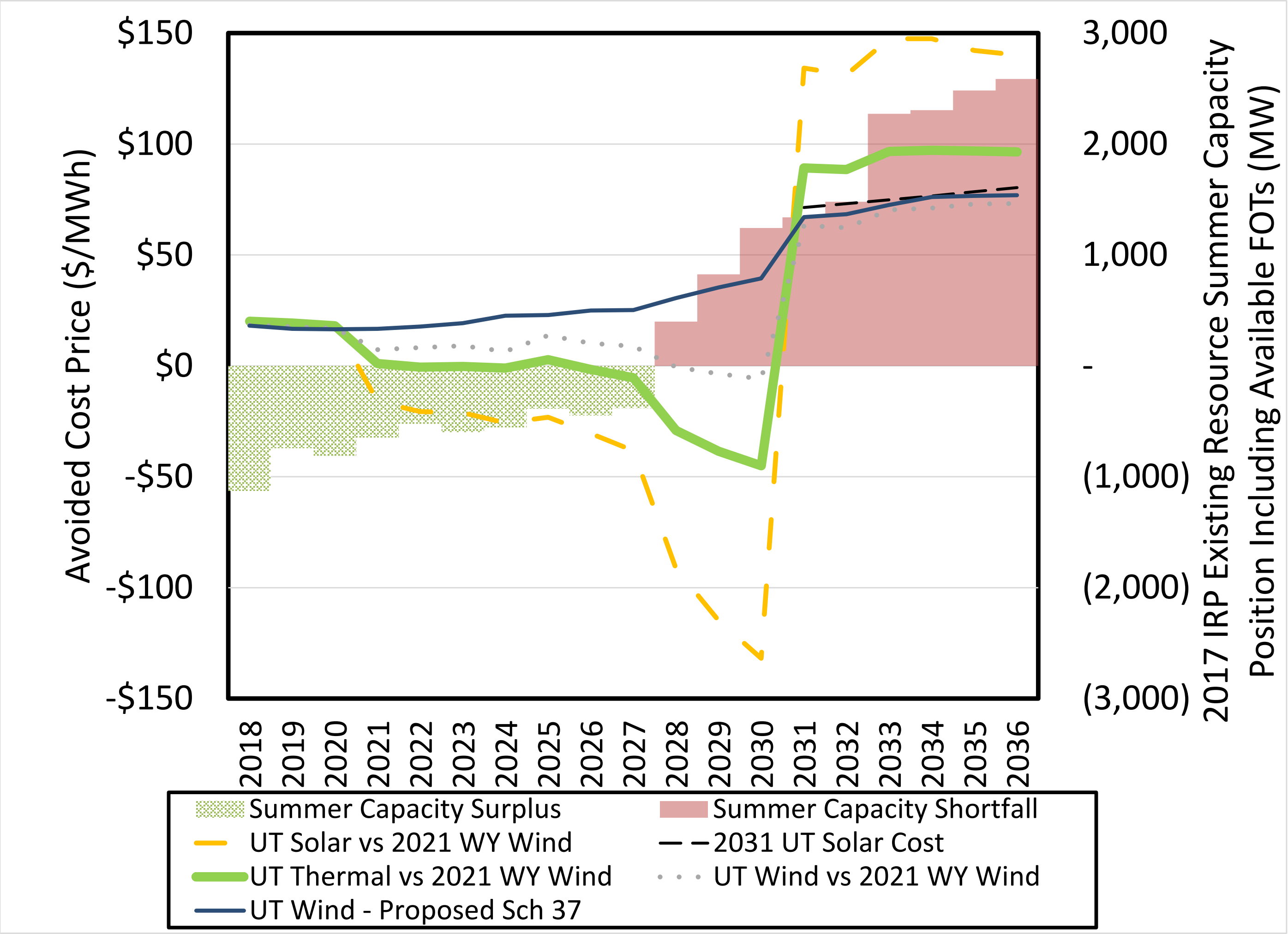
Table 1: Capacity to Energy Ratios

Resource	Capacity Factor	Capacity Contribution	Capacity to Energy Ratio	Displaced MWh 2021 Wind, per QF MWh
Utah Solar	31.1%	59.7%	1.92	4.94
Utah Biomass	100.0%	100.0%	1.00	2.61
Utah Wind	31.0%	15.8%	0.51	1.33
2021 IRP Wind	41.2%	15.8%	0.38	

- The 2021 Wyoming wind resource from the 2017 IRP provides significantly more energy relative to its capacity contribution than a Utah QF.
- At the extreme, each MWh of solar generation in 2021 would displace the energy and PTC benefits of nearly 5 MWh of 2021 IRP wind.
- When the benefits of a QF are less than the net cost and benefits of the displaced resource, avoided cost will be negative.
- Wind QFs that are generating PTCs may be willing to sell at negative prices.

Figure 2: Avoided Cost Assuming Deferral of IRP Wind Resources and No PTC Levelization, by Resource Type, with Existing Resource Capacity Position

- PDDRR, assuming deferral of capacity-equivalent amounts of 2021 Wyoming wind resources
- PTC included during first ten years of proxy resource operation
- PTCs offset most of the capacity cost in 2021-2030 – essentially free energy
- NEW: Avoided cost for Utah wind QF is higher when 2031 IRP wind is deferred



QFs and Renewable Energy Credits (RECs)

- Wyoming – The Company retains RECs from all QFs.
- Idaho – RECs shared 50/50 between QF and Company.
- California – RECs may only be used for CA RPS compliance.
- Oregon – QFs retain RECs, unless they are paid a renewable price that includes RECs
- Utah – currently QFs retain all RECs, unless agreed upon during PPA negotiations
- RECs from QFs are generally allocated to all states (with the exception of Washington).
- The Company has also entered into separate transactions to procure RECs from QFs (where it does not receive the RECs automatically by state policy) for Oregon, California, and Washington RPS compliance. In that instance, the RECs and associated costs are all allocated to Oregon, Washington, and California.

RECs from QFs in 2016

Qualifying Facilities	CA	OR	UT	WY	Grand Total
Biogas			16,345		16,345
Biomass	37,149				37,149
Geothermal		1,884			1,884
Small CA Hydro (Situs)	136,100				136,100
Solar			8,284		8,284
Wind			81,564	526,544	608,108
Total	173,249	1,884	106,193	526,544	807,869

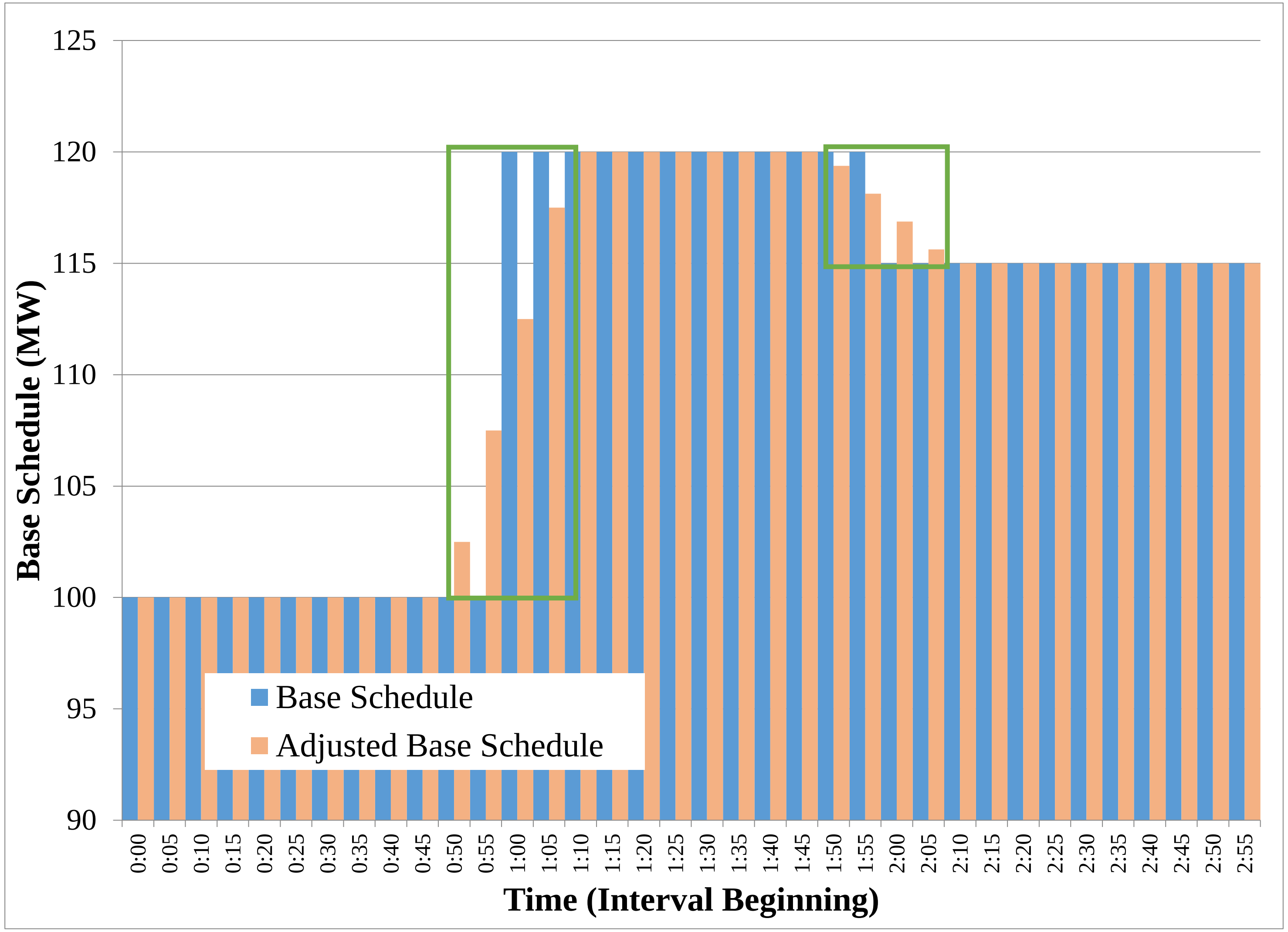
REC RFP Resources	CA	OR	UT	WY	Grand Total
Solar - Bundled			103,730		103,730
Solar - Unbundled			90,802		90,802
Total			194,532		194,532

REC Usage

- RECs usage varies by jurisdiction:
  - California, Oregon, Washington: RECs used for RPS compliance
  - Utah, Wyoming, and Idaho: RECs sold if possible, with revenue returned to customers
  - Utah: RECs could also be retired to meet Utah's state renewable target
  - All: RECs might also be used for compliance with the Clean Power Plan or other future federal regulations.
- The 2017 Protocol cost-allocation methodology expires at the end of 2019. A mutually beneficial cost-allocation methodology could assign a price to extra RECs transferred from Utah to jurisdictions with RPS compliance requirements.
- The Company has a REC Balancing Account (RBA) which tracks the difference between REC revenue included in Utah rates and actual REC revenue collected through PacifiCorp's sales of RECs.
- The Company files annually on March 15th to credit any REC revenue excess or recover any REC revenue shortfall.

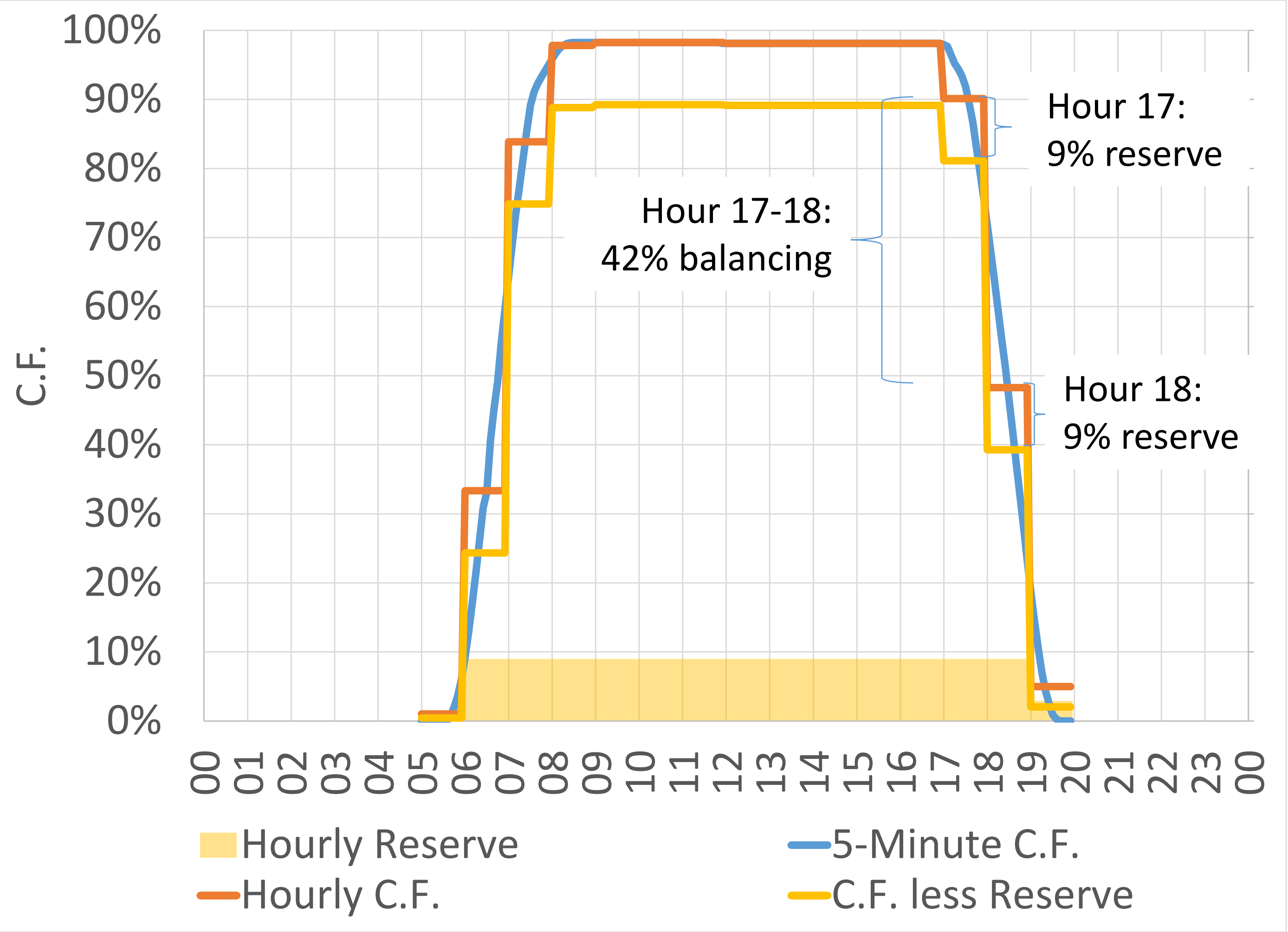
Flexible Capacity Costs – Hourly Scheduling

- Hourly market transactions have impacts over slightly more than a 1-hour period.
- Due to WECC scheduling practices, hourly products transition over a twenty-minute period starting ten minutes prior to an hour.
- The Flexible Reserve Study identifies capacity needed within the hour. The intra-hour effect of WECC scheduling is accounted for in the study (this is Figure F.3)



Flexible Capacity Costs – Hourly Markets

- The Flexible Reserve Study assumes sufficient resources are available to balance the forecasted load and resources on an hourly basis.
- Assuming load is flat, hourly changes in resource output need to be replaced by hourly market transactions or additional dispatchable resources, above those held for intra-hour requirements
- Hourly markets may not reliably have sufficient depth to cover this change, particularly in key hours as solar resources continue to expand across the West.
- Hourly market requirements and depth were not analyzed in the Flexible Reserve Study.



Flexible Capacity Costs - EIM

- Even if hourly forecasts are perfect, intra-hour variations are settled in EIM for each five minute interval
- EIM settlements can result in additional costs if shortfalls occur during periods with higher marginal prices and excess generation occurs during periods with lower marginal prices
- Because large solar ramps occur daily, and are correlated across the EIM footprint, significant variations in marginal prices are possible.
- EIM settlement costs were not analyzed in the Flexible Reserve Study.