Pricing and Hedging Summary for Wind A, Wind B, and Solar

October 24, 2025

Methodology

We start from observable monthly hub forwards F_m (one value per delivery month m). To turn those into realistic hourly prices we layer in three ingredients: (i) an hourly *shape* within the month, (ii) the Day-Ahead vs. Real-Time spread, and (iii) node–hub basis. We model each piece by month and hour-of-day so seasonality is preserved, and we simulate scenarios via bootstrapping or parametric draws that allow negative prices.

From monthly forwards to hourly hub prices. Let h index hours in month m. We use a normalized hourly shape $s_{m,h}$ with monthly mean 1 and add a residual $\omega_{m,h}$ that captures volatility:

$$P_{m,h}^{\mathrm{RT,hub}} = F_m \cdot s_{m,h} + \omega_{m,h}, \qquad \text{with } \frac{1}{H_m} \sum_{h \in m} s_{m,h} = 1, \quad E[\omega_{m,h}] = 0.$$

Day-Ahead hub prices come from adding a DA–RT spread $\Delta_{m,h}$:

$$P_{m,h}^{\mathrm{DA,hub}} = P_{m,h}^{\mathrm{RT,hub}} + \Delta_{m,h}.$$

Both $\omega_{m,h}$ and $\Delta_{m,h}$ are drawn from hour$\times$month empirical distributions (or fitted marginals) so that left tails can cross zero (negative price events).

From hub to node. We add node–hub basis $B_{m,h}$ to get node prices:

$$P_{m,h}^{\mathrm{RT,node}} = P_{m,h}^{\mathrm{RT,hub}} + B_{m,h}, \qquad P_{m,h}^{\mathrm{DA,node}} = P_{m,h}^{\mathrm{DA,hub}} + B_{m,h}.$$

We sample $\{\omega, \Delta, B\}$ jointly so that bad-basis hours tend to coincide with the right times of day and season; in practice we co-sample within the same month-hour bucket, or use a simple copula to reproduce historical rank correlations.

Forecasting generation. We simulate hourly generation G_t ($t \equiv (m,h)$) for each asset.

- **Solar:** we simulate global horizontal irradiance I_t consistent with month/hour climatology and map it to capacity factor,

$$\mathrm{CF}_t^{\mathrm{solar}} = \mathrm{clip}\left(\kappa \frac{I_t}{I_t^{\mathrm{clear}}} \left[1 + \alpha \left(T_t^{\mathrm{cell}} - 25^\circ\mathrm{C}\right)\right] + \varepsilon_t,\ 0,\ 1\right),$$

  then set $G_t = \mathrm{CF}_t^{\mathrm{solar}} \times$ AC rating. The error ε_t (and cloud state) is drawn by month and hour to keep realistic ramps.

- **Wind:** we draw wind speed $V_t \sim \text{Weibull}(k_{m,h}, \lambda_{m,h})$ and apply the turbine power curve $P(\cdot)$:

$$\text{CF}_t^{\text{wind}} = \min\Big\{1,\ \max\{0,\ \tfrac{P(V_t)}{P_{\text{rated}}}\}\Big\}, \quad G_t = \eta_{\text{avail}} \cdot \text{CF}_t^{\text{wind}} \times \text{AC rating}.$$

When prices and generation co-move (e.g., congestion during high wind), we preserve that by co-sampling weather states and basis within the same month-hour strata.

Pricing the as-generated swap. For a chosen product $X \in \{\text{RT\_HUB}, \text{RT\_NODE}, \text{DA\_HUB}, \text{DA\_NODE}\}$ with hourly reference price P_t^X, the generation-weighted average reference price in one scenario is

$$\bar{P}^X = \frac{\sum_t d_t\, G_t\, P_t^X}{\sum_t d_t\, G_t},$$

where d_t are optional discount factors (set to 1 over short horizons). With negative prices *included*, settlement is $\sum_t G_t(P_t^X - K)$. We choose the fixed price K_p so that at protection level p the net value is at break-even; equivalently, we take the p-quantile of the distribution of $\bar{P}^X$ across Monte Carlo paths:

$$K_p \ = \ Q_p\big(\bar{P}^X\big)\,.$$

The expected reference price is $\mu^X = E[\bar{P}^X]$ and the risk premium is $\text{RP}^X = K_p - \mu^X$. If a contract excludes negative prices, we replace G_t by $G_t \mathbf{1}\{P_t^X \geq 0\}$ in all formulas, which shifts the distribution to the right and increases K_p.

Results at $p = 0.75$ with negative prices included

The table shows the most useful columns only: expected generation-weighted reference price μ, the fixed price $K_{0.75}$, and the implied risk premium $\text{RP} = K_{0.75} - \mu$. Values are in $/MWh (rounded).

Asset	Market	μ	$K_{0.75}$	RP
Solar	RT Hub	36.09	36.12	0.03
Solar	RT Node	36.47	37.62	1.15
Solar	DA Hub	36.86	41.44	4.59
Solar	DA Node	36.85	43.24	6.39
Wind A	RT Hub	57.30	57.38	0.09
Wind A	RT Node	48.33	54.50	6.17
Wind A	DA Hub	64.75	72.59	7.84
Wind A	DA Node	55.51	70.03	14.52
Wind B	RT Hub	45.25	45.30	0.04
Wind B	RT Node	39.95	41.02	1.06
Wind B	DA Hub	45.31	48.10	2.79
Wind B	DA Node	36.77	42.95	6.19

For a quick sense of how protection level changes the answer, the generation-weighted RT Hub fixed prices move only slightly with p:

RT Hub fixed price ($/MWh)	$p = 0.50$	$p = 0.75$	$p = 0.90$
Wind A	57.31	57.38	57.47
Wind B	45.25	45.30	45.41
Solar	36.09	36.12	36.15

Discussion

The way we handle volume and price risk in this setup is to separate what can be hedged cheaply from what is expensive. The price component at the hub is efficient to hedge: the RP numbers at RT Hub are essentially zero for Solar, Wind A, and Wind B, which means locking a hub-settled as-generated swap covers the broad market level without paying much of a premium. The expensive parts show up as basis and DA effects. At the node, especially for Wind A, the risk premium becomes large because congestion and correlation with windy hours pull the left tail down; at DA the premium increases again because DA–RT spreads can be unfavorable on exactly the hours you produce. Volume risk is managed implicitly by using as-generated settlements and by computing generation-weighted prices; if one wanted to go further, a volume-firming add-on or simple caps/floors on extreme hours could be layered on top, but the table already tells us where the biggest costs live.

Negative price events matter because they thicken the left tail exactly where the project is most exposed. You can see the impact in the size of the premiums at DA Node across all three assets, and it is most striking for Wind A with roughly $14.5/MWh of premium. That is the price of protection when hours with strong output can also post deeply negative nodal prices. Because our simulations allow prices to cross zero, that tail risk is fully reflected in $K_{0.75}$.

If the offtaker will not take generation when prices are negative, we simply remove those hours from settlement by multiplying by $\mathbf{1}\{P_t \geq 0\}$. In distribution terms, we delete the worst tail and shift the generation-weighted price to the right. The immediate effect is that the fair fixed price goes up: the seller is no longer paying for the worst hours, so the buyer must expect to pay a bit more for the remaining, less risky hedge. The size of the shift will be largest for products and assets where negatives were most common and most correlated with output; based on the table, DA Node for Wind A would see the biggest adjustment.

Some markets are clearly more amenable to hedging than others. RT Hub is consistently the easiest place to set a fixed price: tiny risk premia across Solar, Wind A, and Wind B indicate a clean hedge of the market level with minimal complexity. DA Hub and the two node products are progressively harder because they add DA–RT spread and basis risk on top of the market level. In places that look like Wind A's node, a five-year node-settled price can be expensive enough that it is reasonable to either keep some merchant exposure or, more prudently, lock the hub price and leave the basis piece to be managed separately with CRRs/FTRs or shorter-dated basis trades when they are attractively priced.

There are a few pieces of data that would sharpen the analysis further even though the high-level conclusions are already clear. It helps to know, by hour and season, how often the node actually goes negative and how those hours line up with each asset's production profile; it helps to have a history and forecast for DA–RT spreads at the hub and basis at the node; it helps to understand local outage patterns and any structural congestion that could worsen basis exactly during windy hours; and it helps to know whether financial transmission rights are available on the relevant paths at reasonable cost. With those in hand, we can refine the sampling, tighten the basis and DA modeling, and convert the broad guidance above into a more specific hedge design for each project.