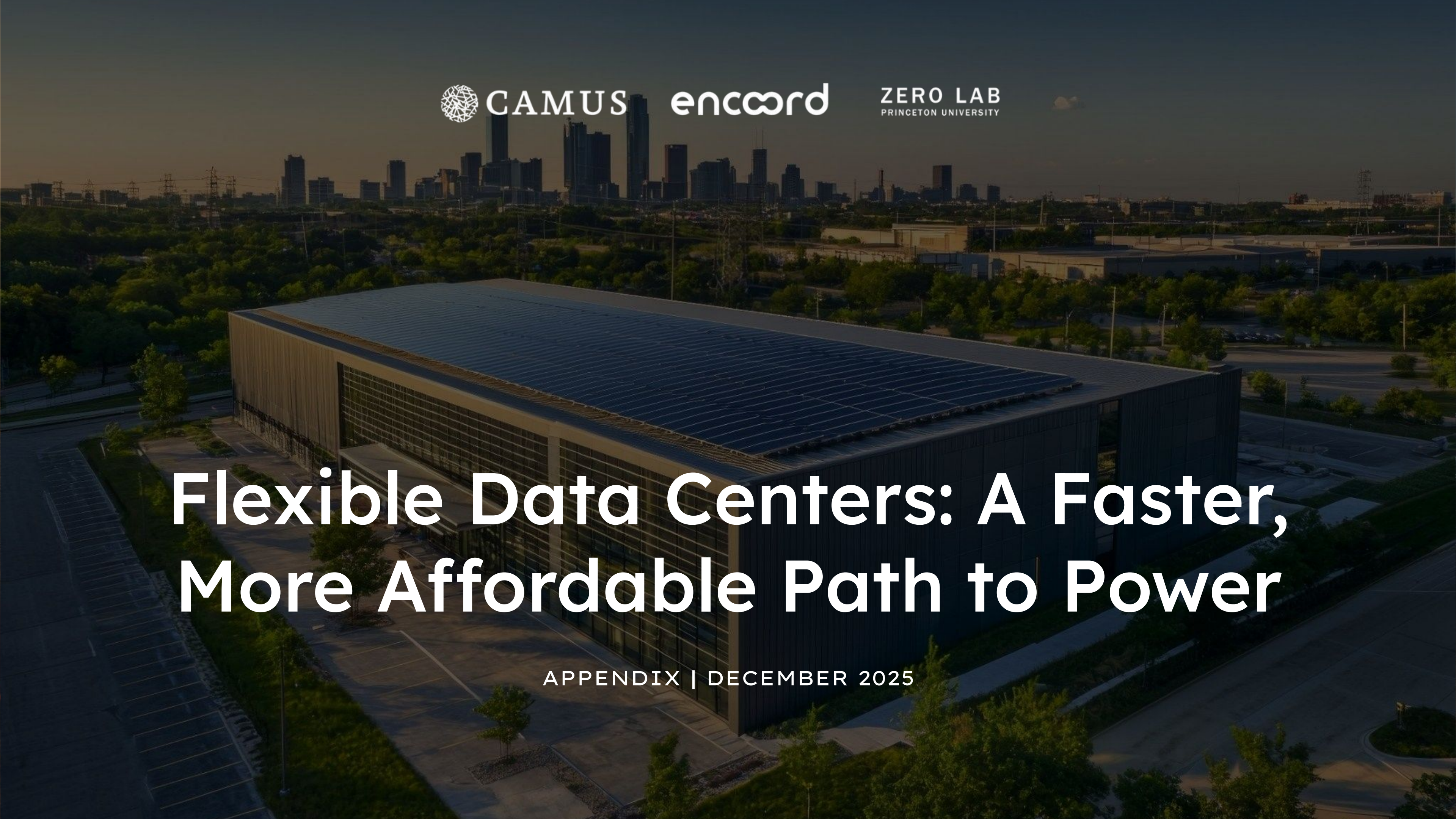

CAMUS encoord ZERO LAB PRINCETON UNIVERSITY

# Flexible Data Centers: A Faster, More Affordable Path to Power

APPENDIX | DECEMBER 2025

APPENDIX A

# Key Assumptions

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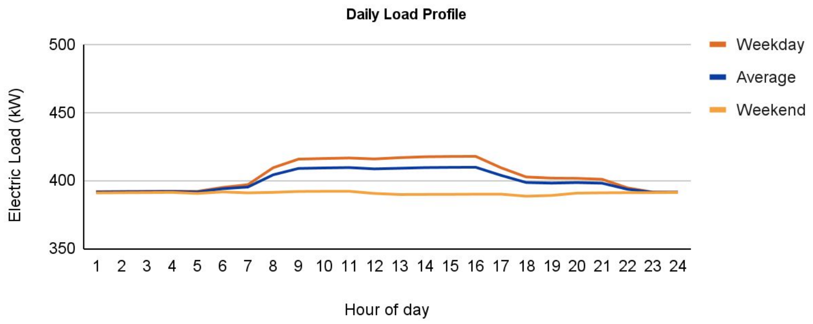
# Data Center Load Profile & Flexibility

## Data Center Specifications

- Nameplate Capacity: 500 MW
- Peak Demand: 435 MW
- Utilization Rate: 87%
- Load Factor: 80%




## Compute Flexibility Parameters

- Duration: Max of 10 hours per call
- Magnitude: 25% load reduction
- Annual Limit: Two cases with 20 and 100 hours maximum per year respectively

## Revenue Impact

- Lost Revenue: $8,000,000 per MW per year[1]

[1] *Average of estimated AI revenue and colocation rental fees ([The Network Installers](); [CBRE H2 2024]()); verified via primary industry interviews*

# Retail Rate Structure

**Large general service tariff (specific costs disguised for confidentiality)**

- Distribution Charge: ~$800 - $1,200/month[1]
- Transmission Service Charge: ~$45 - $65 per kW-month[1]
- Generation Supply (Energy): Hourly real-time LMP (average $0.027/kWh)[2]
- Generation Supply (Capacity): $269.92 per MW-day[3] (equivalent to $8.10/kW-month)

[1] *Utility Tariff Schedule*
[2] *PJM Real-Time Hourly Locational Marginal Prices at utility Residual Aggregate Node*
[3] *PJM Capacity Market Auction clearing price (2025/26 delivery year)*

KEY ASSUMPTIONS

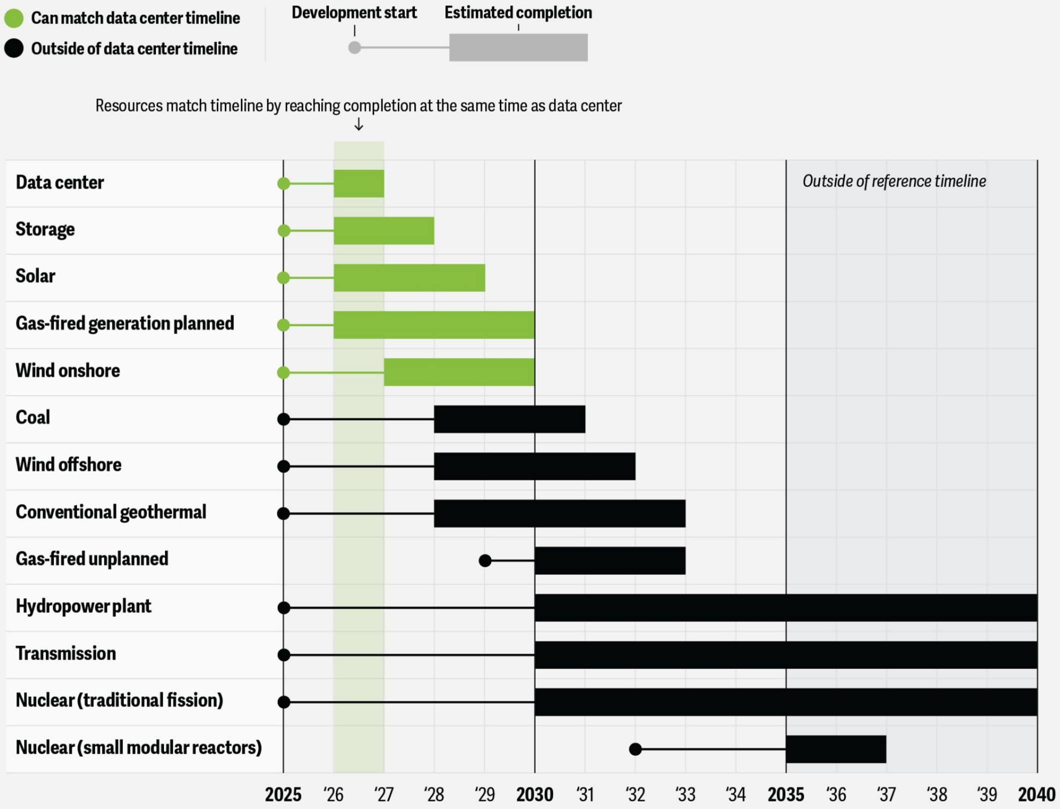
# Technology Timelines

| Technologies (in Analysis) | Years[1] |
|---|---|
| Data center construction | 2 |
| Battery Storage | 2 |
| Solar PV | 2 |
| Wind (On-Shore) | 2 |
| Virtual Power Plants | 2 |
| Natural Gas Gensets (On-Site) | 2 |
| System capacity (unplanned) | 5 |
| Transmission buildout (major) | 7 |

[1] Deloitte meta-analysis

*Figure 9*

**Few energy resources align with data center timelines**




Source: Deloitte analysis of data from International Energy Agency, Brattle, and Energy Innovation reports.

Deloitte. Insights | deloitteinsights.com

# Technology Size Limits

| | Technology | Size limit |
|---|---|---|
| System level | Natural Gas Plant | 75 GW[1] |
| | Solar PV | 32 GW[2] |
| | Wind | 2 GW[2] |
| | Battery Storage | None |
| Offsite[3] | Solar PV | 2 GW |
| | Wind | 50 MW |
| | Virtual Power Plants | 50 MW |
| Onsite | Solar PV | Capped at DC peak load |
| | Battery Storage | 4-hour duration capped at DC peak load |
| | Natural Gas Gensets | Capped at DC peak load |

[1]*Brattle analysis: 80 GW in national queues, supply chains limit to ~50 GW by 2030 (35 GW built nationally over last 5 years)*
[2]*GenX candidate project areas total available capacity in model zone*
[3]*See "Available PPA Capacity (PJM)" slide in Appendix C for more details*

# Site Level Capacity Accreditation (ELCC from PJM)

Site-level analysis uses average ELCC projected through 2034/35[1] which offset the capacity charge portion of the tariff (for which we use the 25/26 clearing princes from the PJM RPM)[2]. The system level modeling does not use ELCCs as inputs but rather calculates them as a result of resource mix.

| | Technology | ELCC |
|---|---|---|
| Offsite | Solar PV | 6% |
| | Wind | 23% |
| | Virtual Power Plants | 59% |
| Onsite | Solar PV | 6% |
| | Battery Storage | 46% |
| | Natural Gas Gensets | 83% |

[1]*PJM Planning Committee, August 6, 2024, "Supplementary Information - ELCC Class Ratings"*
[2]*See "Retail Rate Structure" slide for more information*

# Technology costs & incentives

| Assumption | NG Plant (1-on-1 CC, H-Frame) | NG Combustion Turbine (F-Frame) | Solar PV | Battery Storage | Natural Gas Genset |
|---|---|---|---|---|---|
| Capital cost ($/kW) | $2,400[2] | $1,750[2] | $1,557[3] | $1,418[3] | $1,600[4] |
| Fixed O&M $/kW-yr | $41.09[3] | $27.17[3] | $21.15[3] | - | - |
| Variable O&M ($/kWh) | $0.00263[3] | $0.00744[3] | - | - | $0.014[5] |
| Fuel cost ($/MMbtu)[1] | $4.51 | $4.51 | - | - | $4.51 |
| Incentives | - | - | 5 year MACRS | 5 year MACRS; 30% ITC | - |

Performance and cost assumptions not listed here indicate default values in NREL's REopt model & Princeton's GenX model were used

*[1]Inflated AEO electric power sector middle-atlantic region projection for 2030 by $1.74/MMBTU to reflect difference between AEO and more recent STEO projections for 2026.*
*[2]Halcyon provides a reference based on a review of number of regulatory filings. These filings point to higher costs of roughly $2200/kW - $2500/kW. NextEra's CEO has said publicly on multiple occasions that CCGT costs have risen to $2400/kW to $2500/kW. Others have confirmed this $2400/kW number.*
*[3]2024 Annual Technology Baseline (ATB), NREL. Based on research, we use the conservative values for PV capital cost and O&M costs, and Advanced cost for BESS. Both costs escalated to 2025 costs using CPI inflation calculator.*
*[4]Recent reports from small scale CT / solar engine / RICE engine show costs potentially approaching $2000/kW. Recent filings in Canada confirm this more inflated number, while other filings point to a slightly lower cost ($1300/kW). $1600/kW seems like a reasonable midpoint reflecting the inflationary environment that we're seeing today.*
*[5]REopt default for largest class (class 7) reciprocating engine*

# PPA Price

| | Technology | PPA Price |
|---|---|---|
| Offsite | Solar PV | \$79.17/MWh[1] |
| | Wind | \$80.12/MWh[1] |
| | Virtual Power Plants | \$123.00/kW-year[2] |

[1] *Cost of tier 1 solar resources and tier 2 wind resource (likely to be marginal resource) in utility territory after inflating all PJM wind and solar projects to match LevelTen price trends*
[2] *Real Reliability The Value of Virtual Power, Brattle*

# Tier 3 Financial Assumptions

## Project Finance Structure

- Financing Model: Third-party financed
- Analysis Period: 25 years[1]
- Discount Rate (nominal): 6.38%[2]
- Effective Tax Rate: 26.0%[1]

## Escalation Rates (nominal)

- Electricity: 1.8% per year[3]
- Natural Gas: 4.0% per year[3]
- O&M: 2.5% per year[2]

[1] ASTM E917-17, *Standard Practice for Measuring Life-Cycle Costs of Buildings and Building Systems*
[2] *2024 Annual Technology Baseline (ATB), NREL*
[3] *EIA Annual Energy Outlook 2025, nominal industrial prices 2025-2050*

KEY ASSUMPTIONS

# Tier 3 Emissions

Hourly emissions long run marginal emission rates for the PJM East region of the Cambium dataset[1] used for this analysis.

Additional metrics information:

- Busbar (no distribution losses)
- $CO_2$ equivalent
- Combustion (emissions from direct combustion not including pre combustion)

[1]Cambuim 2023

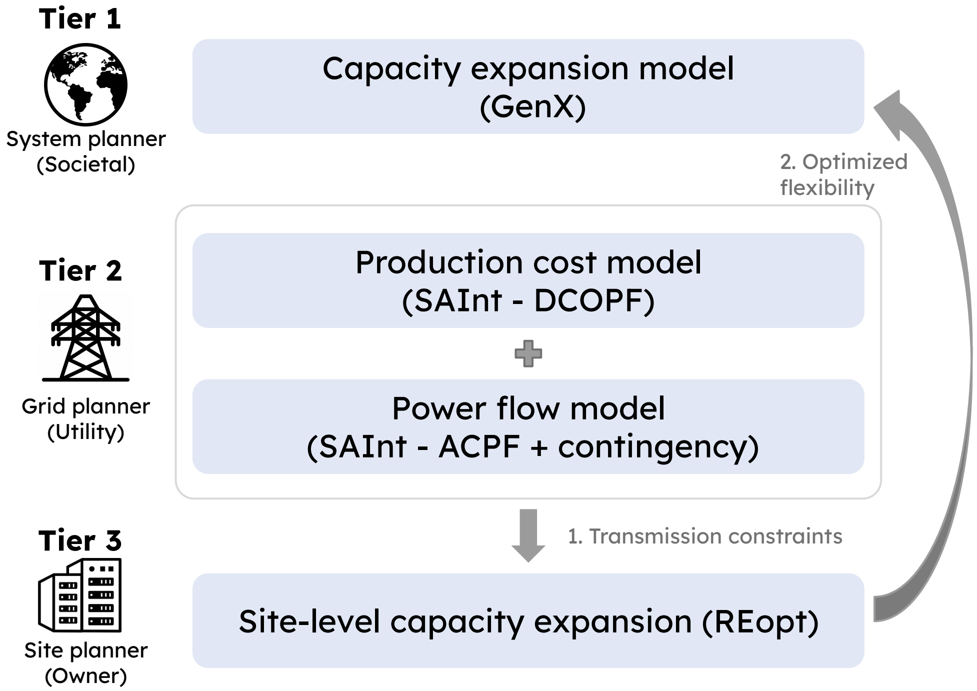
APPENDIX B

# Methodology

# Three-level modeling: from PJM to the individual data center

| | Modeling Approach | Role in Analysis |
|---|---|---|
| **Tier 1**<br>System planner (Societal) | Capacity expansion model (GenX) | Evaluates **system buildout to meet forecasted load growth** under a variety of scenarios (including data center flexibility at scale) |
| **Tier 2**<br>Grid planner (Utility) | Production cost model (SAInt - DCOPF) | Identifies **generator dispatch** that minimizes cost and identifies **required load flexibility** |
| | + Power flow model (SAInt - ACPF + contingency) | Detailed simulation of transmission system (including contingency analysis) to **establish security constraints** |
| **Tier 3**<br>Site planner (Owner) | Site-level capacity expansion (REopt) | Identifies **technology types, sizes that address transmission constraints and minimize cost** for the data center |

# Integrated Modeling to Analyze Interplay Between Perspectives




Two primary data exchanges helped support the analysis

1. Transmission constraints identified in Tier 2 were passed as an 8,760hr time series to the Tier 3 modeling to evaluate sizing that would address those constraints
2. Conditional firm portion of the interconnection (established in Tier 3) was used to inform the range of the flexibility sensitivity modeled in Tier 1

Additionally, technology and cost assumptions were shared between models where possible

# GenX Model → What is it and how does it work

GenX, a least-cost optimization model formulated as either a linear or mixed integer program, takes the perspective of a centralized planner to determine the cost-optimal generation portfolio, energy storage, and transmission investments needed to meet a pre-defined system demand, while adhering to various technological and physical grid constraints, resource availability limits, and other imposed environmental, market design, and policy constraints.

The GenX model is populated with data primarily from PowerGenome. PowerGenome combines data from various public sources (including FERC, EIA, EPA, and NREL) to characterize the grid region(s) of interest, the forecasted load profiles, existing and available generation, and cost and operating characteristics of the various generation/storage technologies included in the model.

# Market Scenario Modeling

- Optimizes PJM-wide system expansion from the present through 2030
- Three primary scenarios:
  - **Baseline –** reflective of current PJM load forecasts and ELCCs
    - Establishes the 2030 system solution for ~24GW of new data center demand, ~11GW of non-data center demand, and ~20GW of retirement by that date
  - **Low Demand** - reflective of a low data center demand case
    - Removes 11.8 GW of the data center load growth and is used in our analysis to reflect the low data center case to which we compare the baseline and flexible demand scenarios (flexible demand described on the next slide)
  - **Summer Peak Risk –** reduces the derating factor applied to PJM solar power ELCCs, reflecting a scenario where summer is the peak risk season

# Flexible Demand Modeling

- Building upon the baseline scenario described in the previous slide, we model three flexibility scenarios:
  - **20%, 40%, and 60% demand flexibility** where the incremental data center demand (incremental being the 11.8 additional gigawatts from the low demand to the baseline scenario) can curtail up to X% of its total demand (reflecting that portion of the data center demand being conditional firm)
- We model this by including a demand flexibility technology that has no capital cost, and a marginal cost that is high enough to not be included in the dispatch stack, but sufficiently low that the model uses it to avoid constructing new generation resources.
  - The flexibility technology does not have a capital cost because these are resources that the data center would develop and use to support the conditional firm portion of their demand. The marginal cost is tuned such that the data center will consume grid power at all times that it is available, yet can be curtailed to avoid capacity build out.

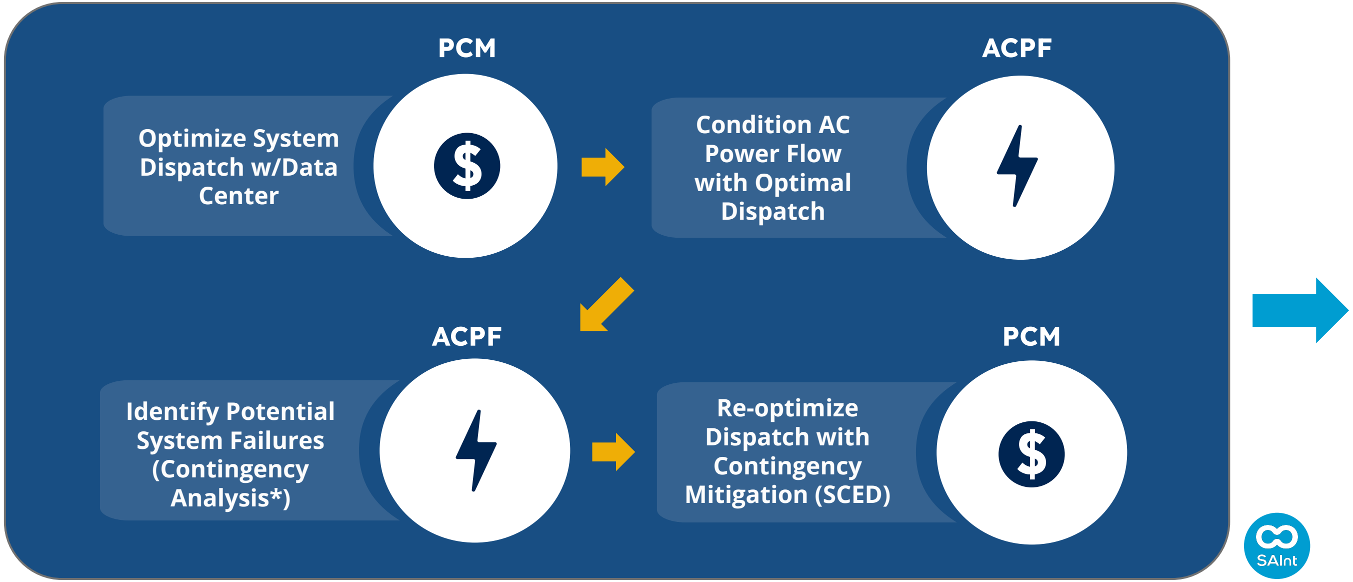
# Integrated Generation & Transmission Planning Model of Utility Territory

Key inputs to the grid planner model

- Transmission planning base case
  - Utility provided a summer peak demand case for 2025
- Economic data and assumptions
  - Generator locations, types, costs, capabilities
- Load and weather profiles
  - 8,760hr T-SCADA data used to establish the load for the PCM
  - Data center 8,760hr load profile
- Geospatial data for transmission system
  - Used to establish where the six data center site locations would connect

➢ Generates a SAInt model that can be run either as a **Production Cost Model (PCM) or AC power flow (ACPF)** model to evaluate power quality and perform contingency analysis

# Evaluating the Power System with Added 500 MW Data Center Demand




Hourly capability of grid to deliver power to data center considering security constraints.

*A contingency analysis process is applied in the ACPF domain where the loss of a system component is simulated to check the resultant power flow and system voltages. The loss of all generators, and 500/230 kV level transmission lines and transformers are tested individually. If violations are observed, these constitute new constraints that are applied in the PCM domain that will further limit the power deliverability capability to the proposed data center, requiring further flexibility.

TIER 2 - GRID PLANNER

# Data Center Sites

- 6 sites across an area of ~1,700mi$^2$ with maximum distance between any two sites of ~130mi
- Diversity in substation infrastructure and nearby generation
- Simulated each through the previously described workflow (at various sizes)
- Output → “Unmet load hours” (essentially the data center load that is not able to be served by the system)

| Site | Interconnection Voltage Level | Line Connections | Peak Utilization | Additional Notes |
|---|---|---|---|---|
| Hare | 230 kV | Substation with 230 kV / 69 kV voltage levels<br>Junction of 4 - 230 kV transmission lines | 58% maximum and 42% minimum loading of the set of 230 kV class lines at peak system demand | Approximately 200 MW delivered to 69 kV system at peak demand |
| Koala | 230 kV | Substation with 230 kV / 69 kV voltage levels<br>Junction of 3 - 230 kV transmission lines | 58% maximum and 9% minimum loading of the set of 230 kV class lines at peak system demand | Approximately 70 MW delivered to 69 kV system at peak demand |
| Pony | 230 kV | Substation with 230 kV / 69 kV voltage levels<br>Junction of 2 - 230 kV transmission lines | 22% maximum and 10% minimum loading of the set of 230 kV class lines at peak system demand | Approximately 80 MW delivered to 69 kV system at peak demand |
| Shark | 230 kV / 500 kV | Substation with 500 kV / 230 kV<br>Junction of both 500 kV and 230 kV transmission lines | 58% maximum and 15% minimum loading of the set of 230 kV class lines at peak system demand | POI for thermal generation |
| Snake | 230 kV / 500 kV | Substation with 500 kV / 230 kV / 69 kV voltage levels<br>Junction of both 500 kV and 230 kV transmission lines | 39% maximum and 15% minimum loading of the set of 230 kV class lines at peak system demand | POI for thermal generation<br>Approximately 210 MW delivered to 69 kV system at peak demand |
| Whale | 230 kV | Substation with 230 kV / 69 kV voltage levels<br>Junction of 3 - 230 kV transmission lines | 49% maximum and 6% minimum loading of the set of 230 kV class lines at peak system demand | Approximately 95 MW delivered to 69 kV system at peak |

# REopt → what is it and how does it work

- NREL's REopt model enables optimal selection of technology type, size, and dispatch for (1) meeting data center demand during transmission constrained periods and (2) minimizing costs for the site by reducing utility bill charges
- The model brings all future costs (e.g., annual O&M costs, energy costs, fuel costs etc.) to present value and weighs those against capital investments now.
- To effectively optimize utilization (and the value) of technologies options, it models dispatch decisions for all 8760 hrs in a year


Source for graphic: https://www.nrel.gov/reopt/about/

# Identification of optimal on-site portfolio to solve transmission constraints

To address the transmission constraint and identify optimal onsite/co-located resources:

1. We first reduce the unmet load profile by the available compute load flexibility (max of 20 hours, for a max of 25% of demand in that hour)
    a. This step reflects the fact that the cost of compute flexibility is considered outweighed by the speed to capacity benefits and therefore low/zero marginal cost for a subset of more flexible workloads up to a certain point (in this case, modeled as 20 hours at 25% or less of total load)
2. We then enter the remaining unmet load profile into REopt and size technologies to meet that load profile (where the grid is unable to serve this load)
3. We then conduct a final run where the technology sizes from step #2 above are forced in as minimum sizes and we optimize for any additional cost savings that can be achieved by new technologies or increased technology sizes
    a. This cost-minimization is against the utility tariff and primarily driven by demand charge management or energy arbitrage opportunities

The suite of technologies assessed in the REopt model include PV, BESS, and gas generators

# Identification of accredited capacity options to address generation constraints

Once the onsite/co-located technologies were sized to address the transmission constraints (see previous slide), we then evaluated BYOC approaches to bring accredited capacity for the firm portion of the interconnected demand. This was done by:

- Procuring offsite PPAs or VPP and using the associated accredited capacity for BYOC
    - These were selected from cheapest to most expensive order (on a $/kW of capacity basis). See next slide for details
- If those options cannot provide sufficient capacity (e.g., not enough PPAs available in the queue), co-located resources were selected

Offsite options were prioritized because of their availability in interconnection queues and their alignment with common data center procurement practices, while on-site and co-located resources are modeled as secondary options when off-site accredited capacity is insufficient or slow to deploy.

# Assessing the cost of offsite PPAs and VPPs

We put the VPP and offsite PPAs on a level playing field by:

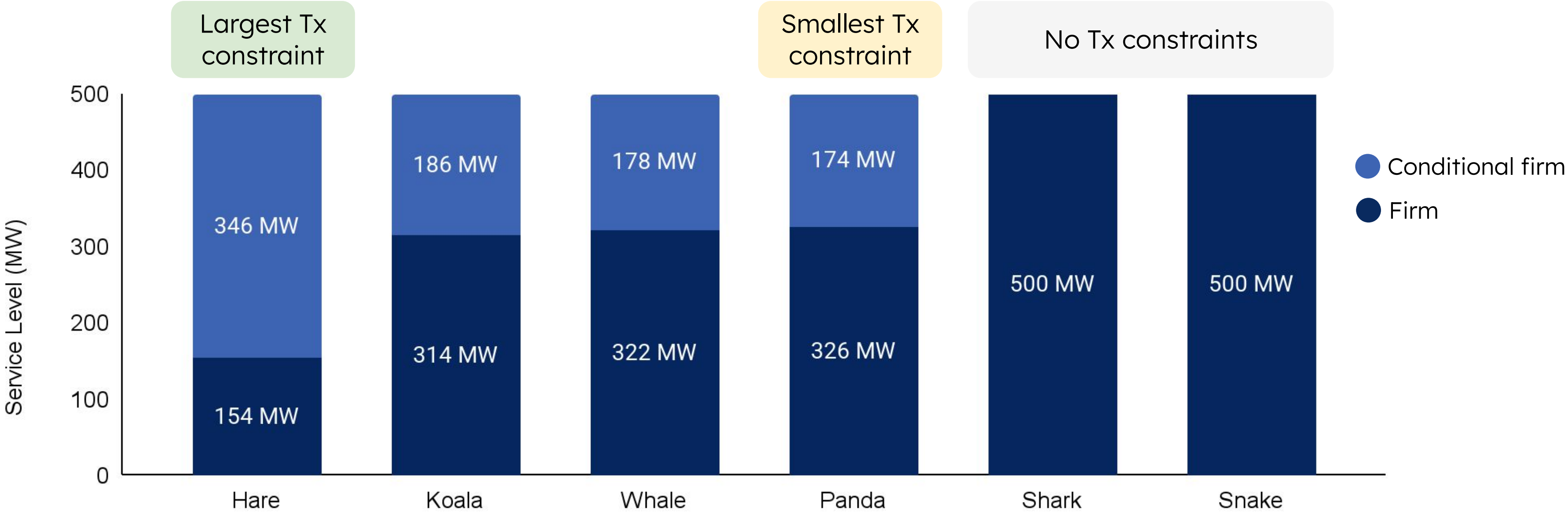
1. Accounting for the energy generation from 1kW of wind and solar and reducing the cost by that amount multiplied by the average LMP (at the node for the site)
2. Converting from $/kWh PPA prices to $/kW prices by multiplying the PPA price by the energy output from a kilowatt of nameplate
3. Converting a kW of nameplate capacity to accredited capacity using average ELCCs for the resource type

| Technology | PPA Price | PPA Cost Accounting for Energy Benefits | ELCC | Cost for Accredited Capacity |
|---|---:|---:|---:|---:|
| Solar PV | $79.17/MWh | $52.58/kWh | 6% | $1,123/kW |
| Wind | $80.12/MWh | $53.53/kWh | 23% | $710/kW |
| Virtual Power Plants | $123.00/kW | - | 59% | $210/kW |

APPENDIX C

# Faster Path to Power

# Firm and conditional firm service levels vary significantly across the 6 sites evaluated

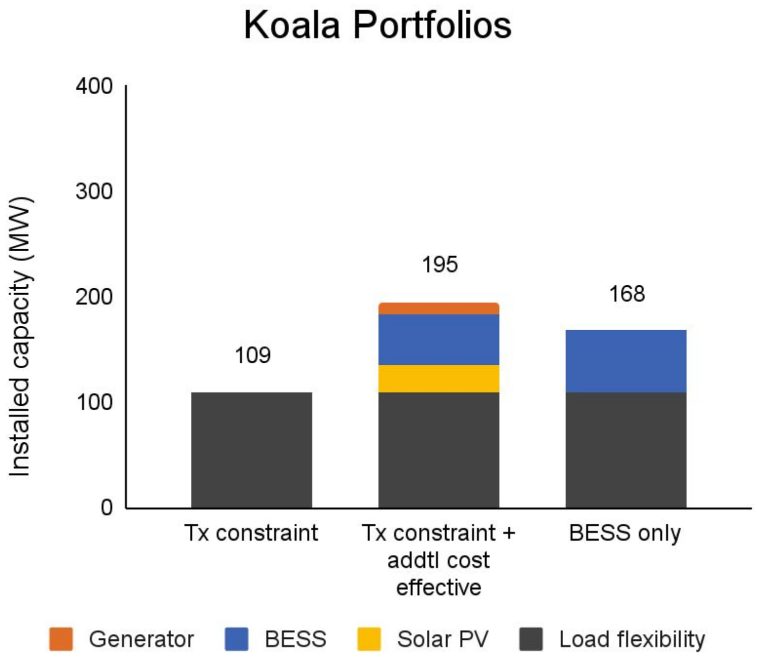


# Optimal portfolios: least transmission-constrained site

For Koala, the load flexibility alone is sufficient to meet the transmission constraint, however **it is cost-effective to add DERs to further reduce the energy supply cost**, including 26 MW of solar PV, 49 MW of BESS, and 11 MW of generator. The additional cost effective DERs are primarily **reducing the >$50/kW demand charge**, but are also dispatched to offset high LMP prices.

When restricting available resources to exclude natural gas generators* and local solar**, a 59 MW BESS is cost-optimal to mitigate energy supply costs.

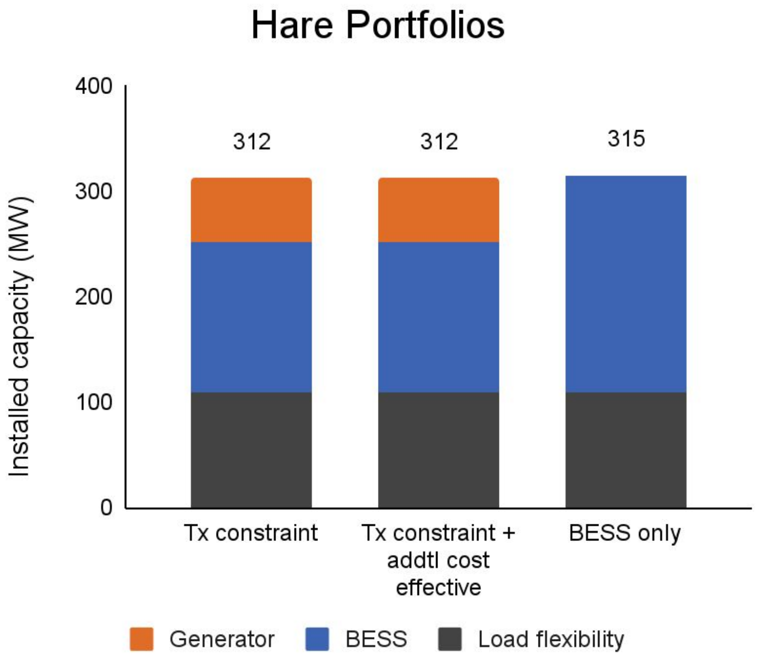
*E.g. to avoid on-site fossil emissions
**E.g. because of physical space constraints



# Optimal portfolios: most transmission-constrained site

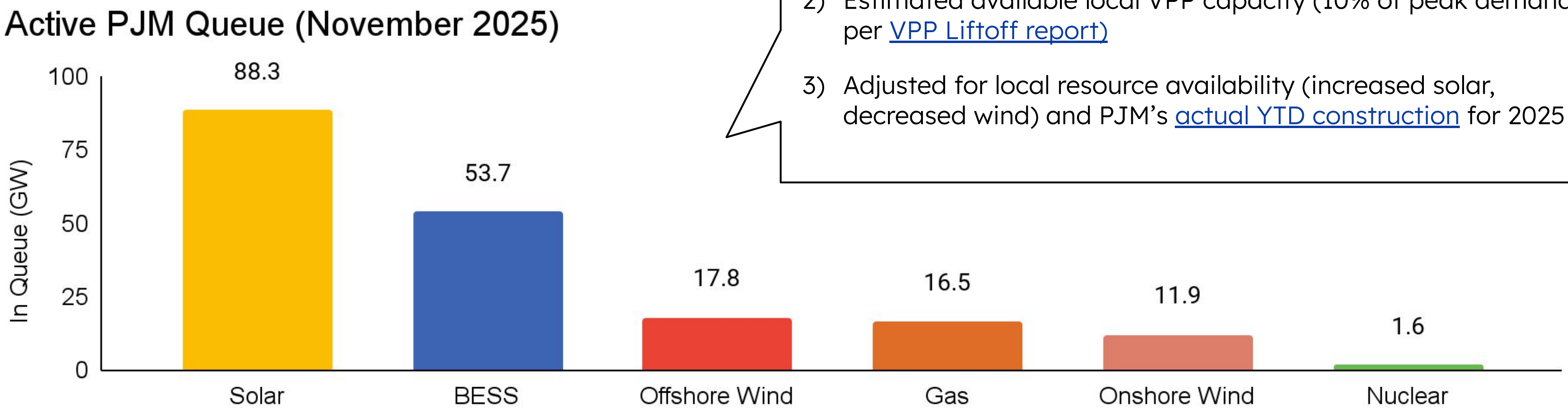
For Hare, the cost-optimal technologies to meet the transmission constraint include a 143 MW BESS and 50 MW generator (in addition to load flexibility); it is **not cost-effective to add additional DERs** to mitigate energy supply costs.

When restricting available resources to exclude natural gas generators*, a 206 MW BESS is required to meet the transmission constraint.




*E.g. to avoid on-site fossil emissions

# Available PPA Capacity (PJM)




**Estimating available PPA capacity per 500 MW data center**

1) Calculated available accredited capacity per data center for eligible in-queue resources (110 MW solar, 57 MW onshore wind)
2) Estimated available local VPP capacity (10% of peak demand, per VPP Liftoff report)
3) Adjusted for local resource availability (increased solar, decreased wind) and PJM's actual YTD construction for 2025

| | Solar | BESS | Offshore Wind | Gas | Onshore Wind | Nuclear |
|---|---|---|---|---|---|---|
| ELCC | 6% | 46% | 30% | 83% | 23% | 95% |
| Accredited Capacity per DC | 110 MW | 515 MW | 111 MW | 285 MW | 57 MW | 32 MW |
| Meet DC Requirements? | **Yes** | No | No | No | **Yes** | No |

Sources: Interconnection.FYI, VPP Liftoff Report, PJM

# Sensitivity analysis: high- and low-PPA availability (in PJM)

The analysis also evaluated the impacts of higher (474 MW per data center) or lower (79 MW per data center) off-site PPA availability on the lifecycle costs for two sites (Hare, Koala). Findings showed that **higher PPA availability drove down per MW PPA costs** ($ per MW) due to more availability of lower cost options and **allowed the data center to procure all firm capacity from PPAs** (though at higher lifecycle costs). Low PPA availability drove up per MW PPA costs ($ per MW) and forced the site with less firm capacity to procure onsite resources, as off-site PPAs were insufficient.

In addition, we modeled the impact of both high- and low-availability using GenX's Summer Peak ELCCs (where renewables had higher ELCCs). The result was significantly lower cost per kW of accredited capacity of clean PPAs, leading to lower total costs across the board.

**PJM ELCCs**

| | Hare | | | | | Koala | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | PPA Capacity Needed (MW) | Added PPA Cost ($M) | Generator Capacity needed (MW) | Added Generator Cost ($M) | Total Cost ($M) | PPA Capacity Needed (MW) | Added PPA Cost ($M) | Generator Capacity needed (MW) | Added Generator Cost ($M) | Total Cost ($M) |
| Current Case | 154 | $1,675 | 0 | $0 | $5,852 | 158 | $1,729 | 203 | $128 | $6,164 |
| High PPA Availability | 154 | $930 | 0 | $0 | $5,107 | 326 | $3,215 | 0 | $0 | $7,522 |
| Low PPA Availability | 79 | $864 | 90 | $57 | $5,099 | 79 | $864 | 298 | $189 | $5,360 |

**GenX Summer Peak ELCCs**

| | Hare | | | | | Koala | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | PPA Capacity Needed (MW) | Added PPA Cost ($M) | Generator Capacity needed (MW) | Added Generator Cost ($M) | Total Cost ($M) | PPA Capacity Needed (MW) | Added PPA Cost ($M) | Generator Capacity needed (MW) | Added Generator Cost ($M) | Total Cost ($M) |
| Current Case | 154 | $433 | 0 | $0 | $4,610 | 326 | $929 | 0 | $0 | $5,236 |
| High PPA Availability | 154 | $409 | 0 | $0 | $4,587 | 326 | $905 | 0 | $0 | $5,212 |
| Low PPA Availability | 154 | $438 | 0 | $0 | $4,616 | 294 | $864 | 39 | $24 | $5,196 |

# Speed to power benefits: key calculations

| **Net return** | = | **Benefit**: the present value of incremental earned EBITDA (via faster path to power) | – | **Costs**: the present value of incremental costs from on-site resources and PPAs |
|---|---|---|---|---|

The economic outcome equals PV of benefits minus PV of costs.

The analysis estimates the value of faster interconnection by assuming between 1 and 5 years of "time gained." For each accelerated year, the team calculated the incremental MW the site would be able to access: the full 500 MW during the years gained from resolving generation constraints, and only the conditional-firm portion in later years when firm generation capacity would have been available under the status quo. Incremental MW were multiplied by the assumed revenue per MW ($4–12M, median $8M)[1] and a 45% EBITDA margin.

The annual EBITDA gains were discounted at 8% (with $0 assigned to the 2 construction years) to determine the present value of speed-to-power benefits.

Incremental costs were calculated by summing the capex of on-site resources with the present value of ten years of opex, and adding the present value of incremental PPA costs (net of avoided PJM energy purchases).

All costs were discounted using the same 8% rate.

*1Average of estimated AI revenue and colocation rental fees (The Network Installers; CBRE H2 2024); verified via primary industry interviews*

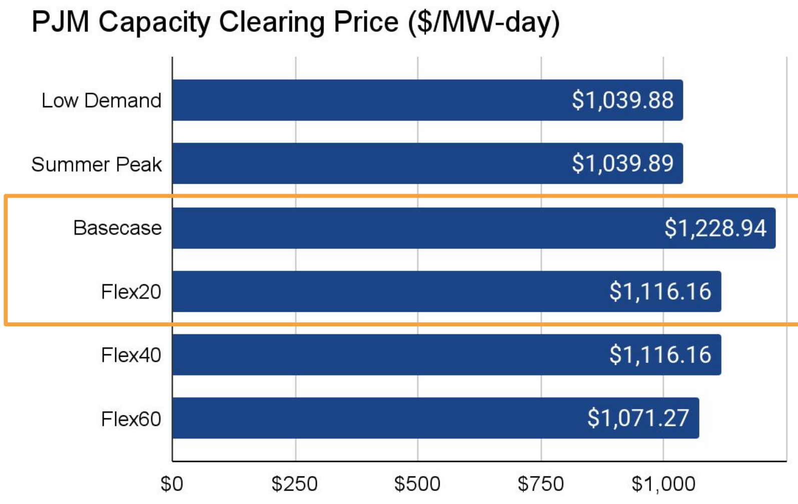
APPENDIX D

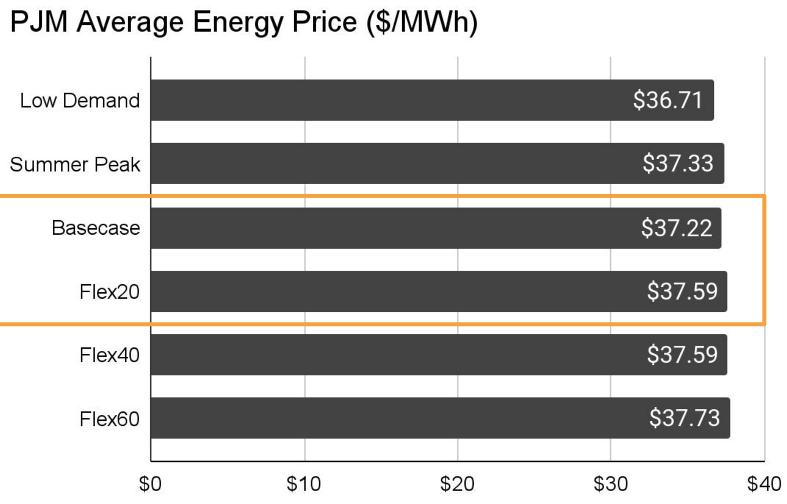
# Incremental System Costs & Affordability

Excludes BYOC impacts

GENX MODEL OUTPUTS

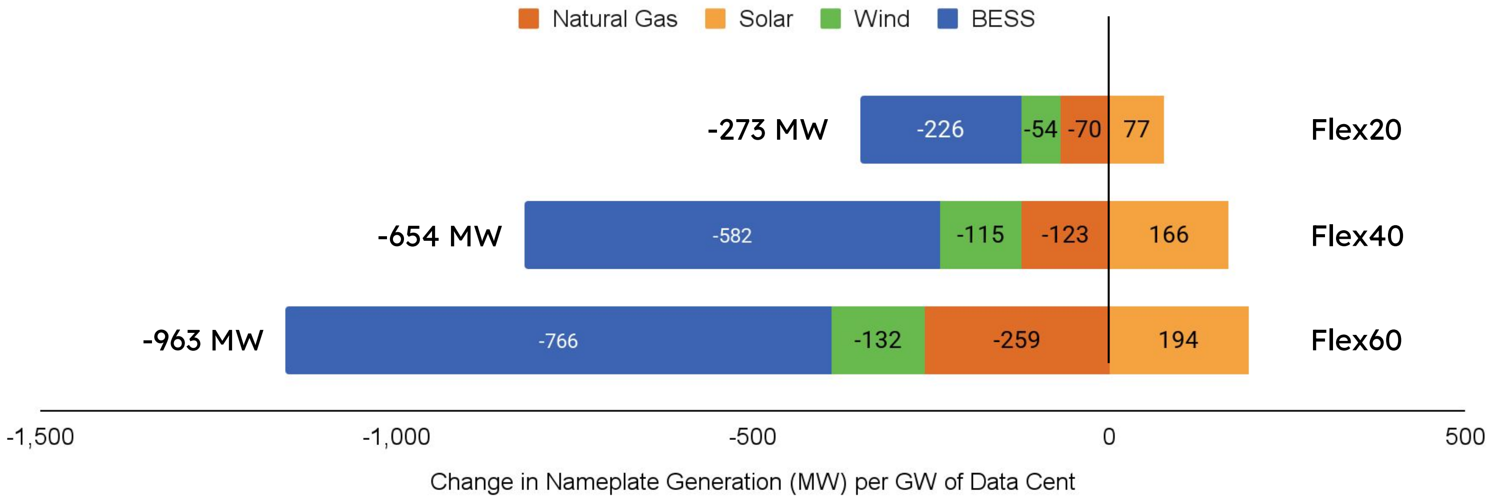
# Capacity and energy prices were analyzed across cases




Capacity and energy prices are outputs from the GenX modeling for the PJM system. Low demand includes ~12 GW of new data center demand, ~11 GW of non-data center demand, and ~20 GW of retirement by that date. Baseline represents PJM's active forecast, which includes 24 GW of data center demand, representing an incremental 11.8 GW of demand. Summer peak reduces the derating factor applied to PJM solar power ELCCs, reflecting a scenario where summer is the peak risk season.

# Flexible connection reduces new capacity builds required to serve 1 GW of new demand




Flex20 refers to serving the incremental 1 GW of data center demand with 20% conditional firm and 80% firm service. Flex40 refers to 40% conditional firm and 60% firm service. Flex60 refers to 60% conditional firm and 40% firm service. All values are avoided buildout of capacity on a nameplate basis, based on different resources mixes provided as outputs from the GenX model.

# BYOC internalizes costs based on clearing price and quantity

| | Base | Flex20 | Flex40 | Flex60 |
|---|---|---|---|---|
| **Additional firm capacity per GW of demand** (Megawatts) | 1,000 MW | 800 MW | 600 MW | 400 MW |
| **Capacity clearing price** ($ per MW-day, converted to $MM per MW-year) | $1,229 per MW-day ($0.45MM/year) | $1,116 per MW-day ($0.41MM/year) | $1,116 per MW-day ($0.41MM/year) | $1,071 per MW-day ($0.39MM/year) |
| **BYOC costs** ($MM per GW of demand) | $449 MM | $326 MM | $244 MM | $156 MM |

Capacity clearing prices are outputs of GenX modeling. Flex20 refers to serving the incremental 1 GW of data center demand with 20% conditional firm and 80% firm service. Flex40 and Flex60 refer to 40% and 60% conditional firm respectively.

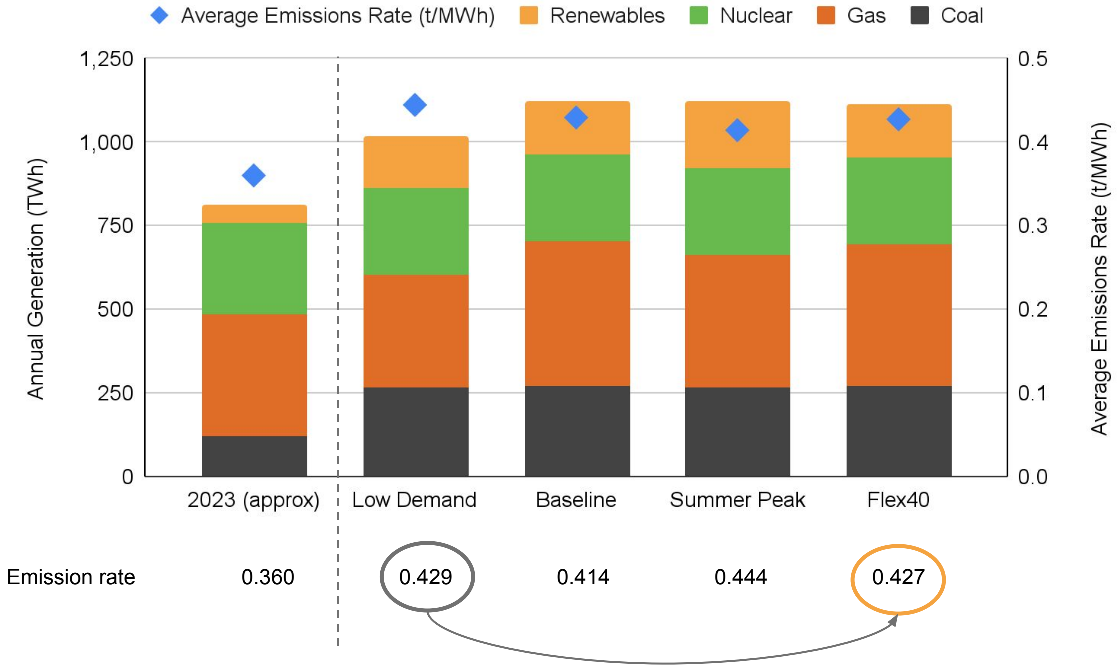
APPENDIX E

# Additional Analyses

# PJM emissions expected to increase, flexibility helps minimally

Baseline: GenX projected an increase in PJM's average emission rate by 2030 due to increasing load, stagnant nuclear contributions, and slow renewable growth, leading to a resurgence in coal-fired generation.

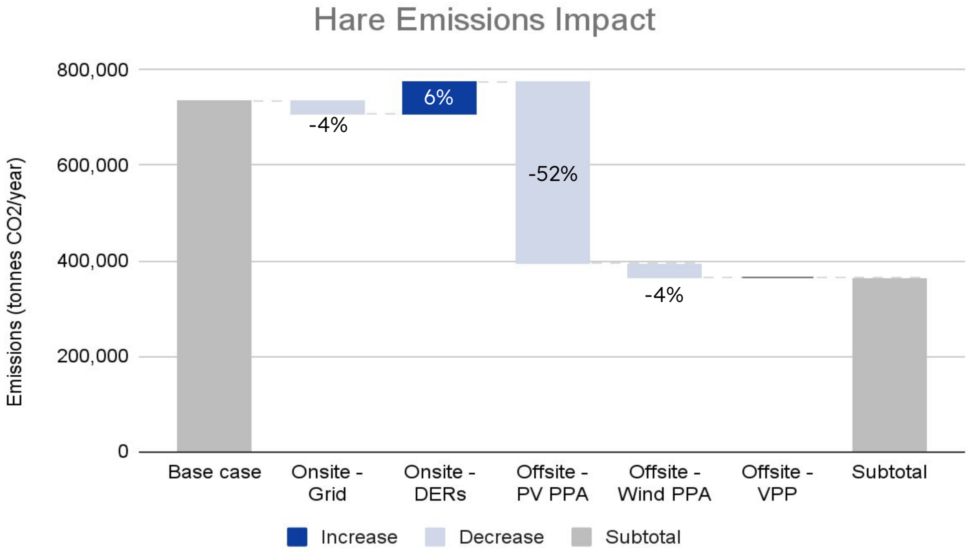
Flexible connections slightly reduce emissions rates, but the impact is minimal and **utilization of fossil generation may increase if not paired with a carbon-free or low-carbon energy procurement strategy by the data center.**



# Hare: on-site DERs increase emissions 6%, PPAs reduce 56%

Chart shows the emissions impact of onsite generation required to meet transmission constraints (plus any additional cost-effective DERs), and off-site PPA purchases to meet capacity requirements. Note the large reduction in emissions from the off-site PPA purchases is driven by the large installed capacity required for accreditation given ELCCs. Onsite DERs lead to a net increase of 6% (reduction from grid purchases plus increase from generator); off-site PPA purchases reduce emissions by 56%.

| | | Accredited (MW) | Nameplate (MW) |
|---|---|---|---|
| Onsite | DC Flex | 0 | 109 |
| | PV | 0 | 0 |
| | BESS | 0 | 143 |
| | Generator | 0 | 60 |
| Offsite | PV PPA | 113 | 1,930 |
| | Wind PPA | 11 | 50 |
| | VPP PPA | 29 | 50 |

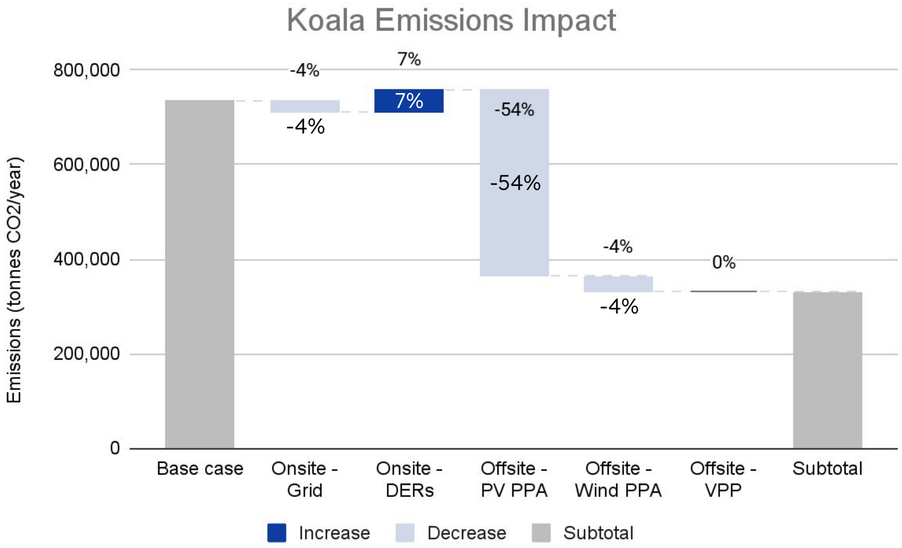


# Koala: on-site DERs increase emissions 3%, PPAs reduce 58%

Emissions impact for Koala are similar; here the onsite DERs (net of fewer grid purchases) increase emissions by 3% while off-site PPAs reduce emissions by 58%.

| | | Accredited (MW) | Nameplate (MW) |
|---|---|---|---|
| Onsite | DC Flex | 0 | 109 |
| | PV | 0 | 26 |
| | BESS | 0 | 55 |
| | Generator | 168 | 213* |
| Offsite | PV PPA | 118 | 2,000 |
| | Wind PPA | 11 | 50 |
| | VPP PPA | 29 | 50 |

*Includes 11 MW of on-site generator capacity that is used to manage supply costs and is not accredited



DLR IMPACT

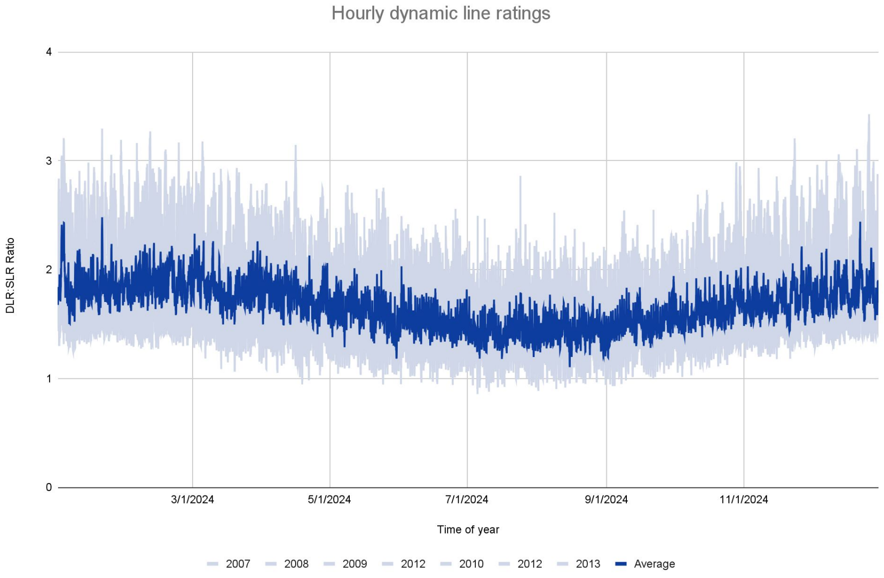
# Simple modeling of DLR implies significant curtailment reduction

The analysis used representative conductors at each primary voltage level (500, 230, and 69kV) to apply increased capacity values based on a national dataset from NREL. The hourly DLR to SLR ratio averaged across 2007-2013 resulted in increased capacity in all hours, but in particular during the winter time when the transmission system is constrained. Applying the DLRs, results showed little to no curtailment would be required across the two sites evaluated.

These results demonstrate that DLR generally has potential to alleviate transmission constraints, yet we note that studies have shown the need for detailed analysis that drives successful applications.

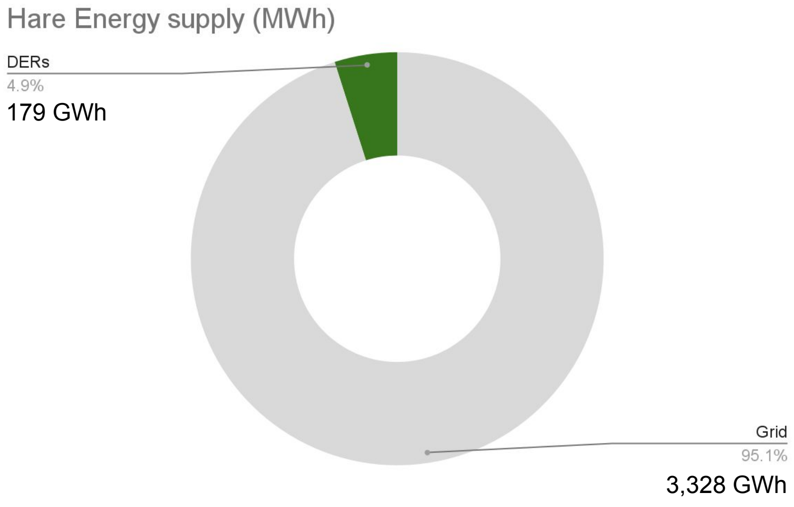
Additionally, the technology needs to be integrated into the utility operations to drive full savings.

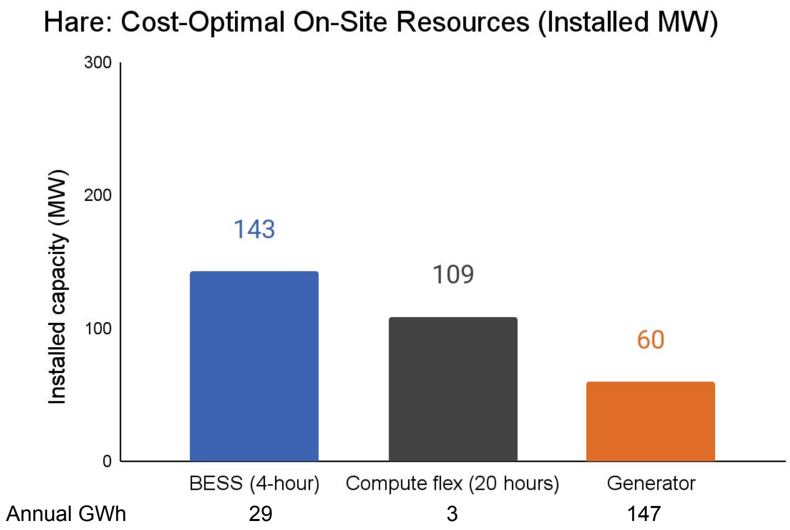
| | Curtailment required by demand level | | |
|---|---|---|---|
| Site | 500 MW | 600 MW | 700 MW |
| Koala | 0 | 0 | 0 |
| Hare | 0 | 0 | 50 MW; 3 hrs |



# Hare: 95.1% of energy supply from grid with cost-optimal mix

While the sizes of DERs to meet transmission constraints represent a large portion of the rated capacity of the data center, they make up a small portion of meeting the load (GWh). The data center flexibility and generator are dispatched sparingly, to meet constraints and occasionally lower demand charges, while the BESS cycles daily to flatten load and lower demand charges.

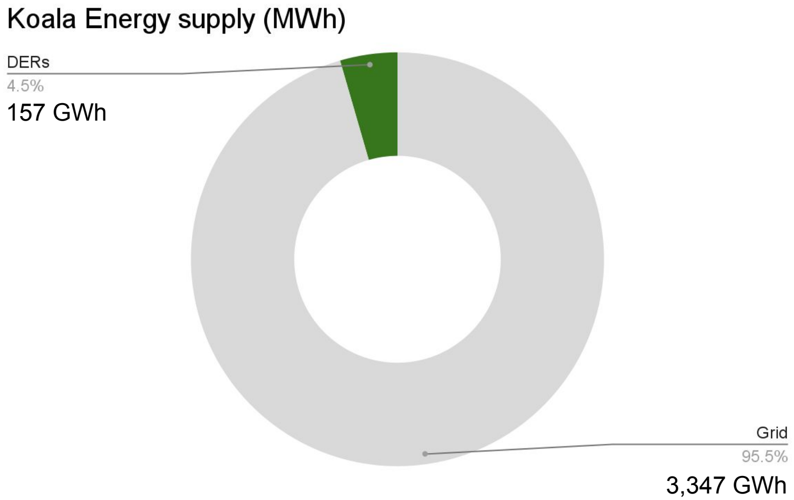


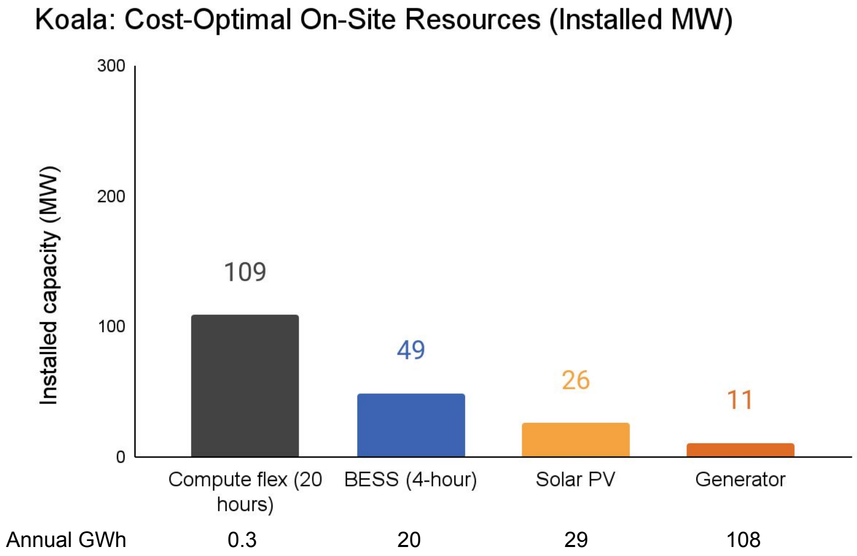



ENERGY MIX

# Koala: 95.5% of energy supply from grid with cost-optimal mix

While the installed capacities needed to meet the transmission constraint at Koala are smaller, the impact on contribution to data center load doesn't change significantly.

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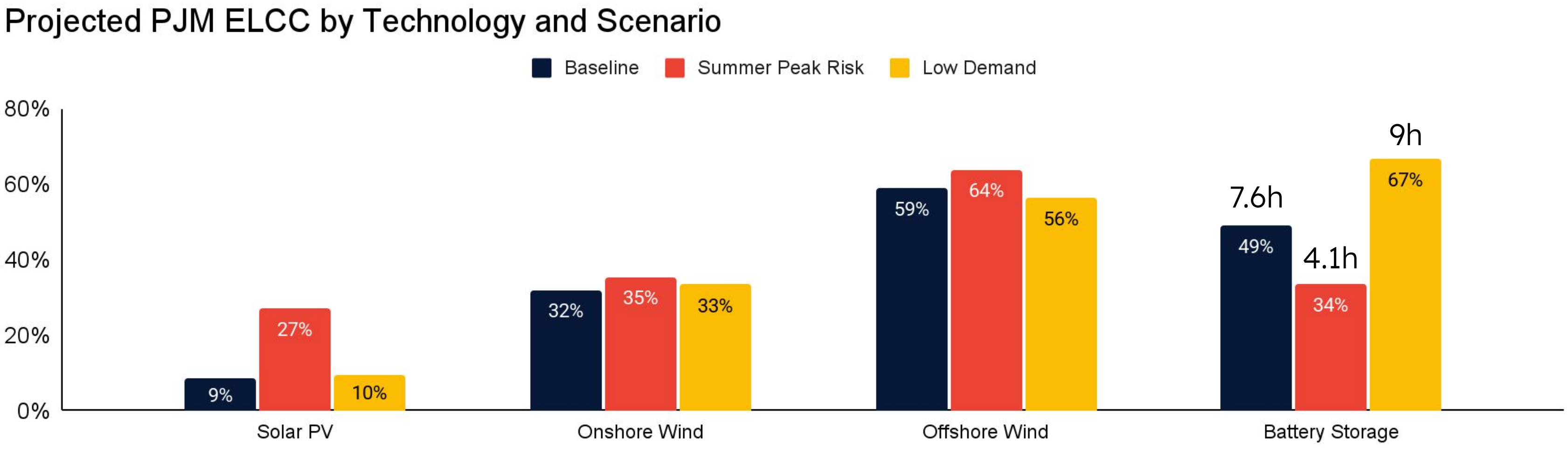
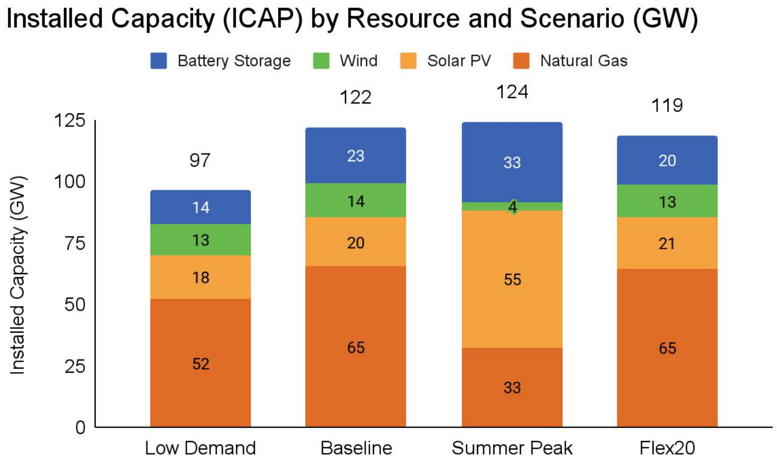
# ELCCs by market scenario

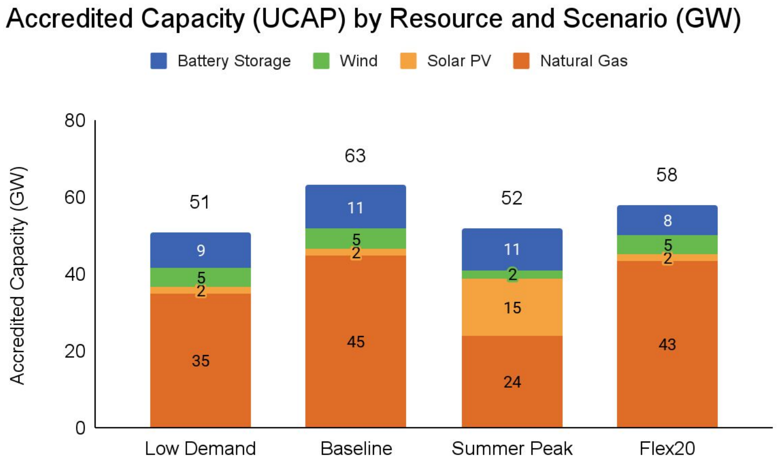
- Anticipated ELCCs are calculated based on each technology's marginal reliability contribution during capacity-constrained hours, multiplied by a derating factor
- Solar ELCCs are low except in the Summer Peak Risk scenario; wind & storage are higher



# Capacity builds by market scenario

- Gas resources supply a significant portion of incremental PJM capacity to meet baseline demand growth in all cases
- Storage is optimally deployed at very long durations in most cases, reflecting very high capacity prices driven by gas limitations
- Much greater reliance on solar is possible if peak risk occurs in summer
- In UCAP terms, gas makes up the large majority of new installed capacity in all scenarios except Summer Peak Risk
- ~2.4 GW of data center flexibility (11.8 GW with 20% flexibility) reduces total accredited capacity requirements by ~5 GW



# Adding all 6 data centers (at 700 MW nameplate) at the same time leads to complex outcomes → further analysis required

The table below shows the impact of adding 4.2 GW of data center load (700 MW at each of the 6 sites evaluated) compared to 500 MW at each site (individually).

Overall curtailment increases, particularly for the most constrained site(s), likely due to transmission congestion being contained to a small number of lines. This highlights both the **importance of continued transmission upgrades** for the most constrained lines and the **need to study large load additions in correct sequence** (clustered or one-at-a-time). It's unlikely all six of these data centers would interconnect at the same time, in the same region, but it would clearly increase the size of on-site resources required to manage network constraints.

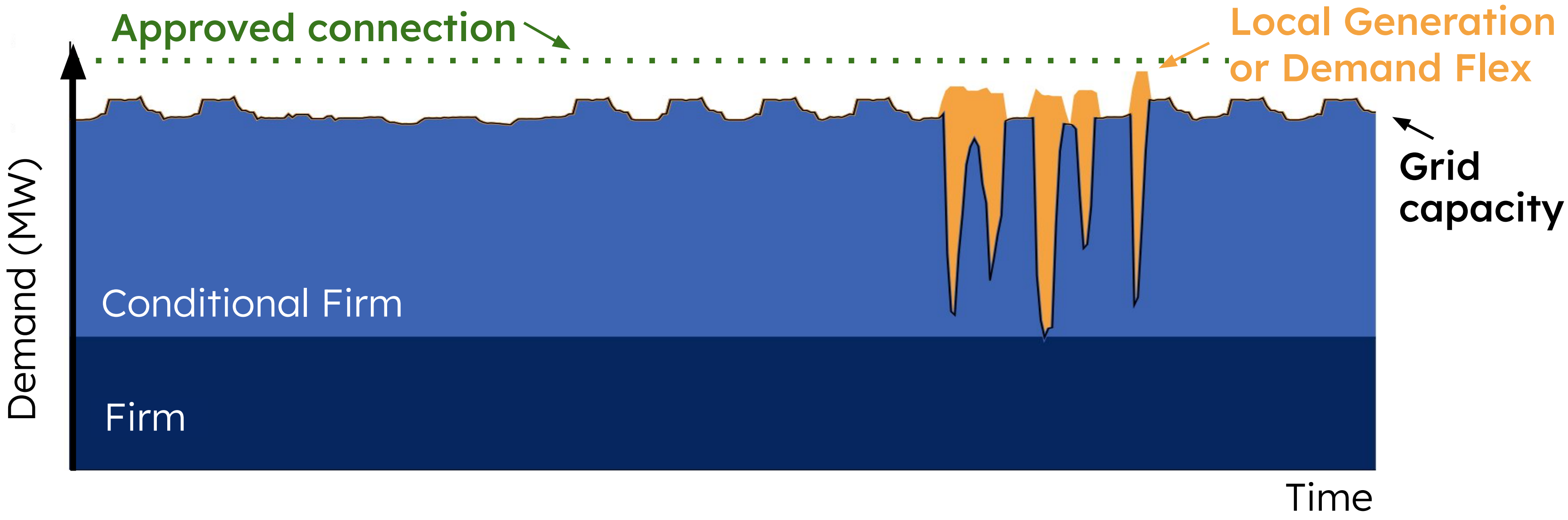
| Transmission constraints | 4.2 GW DC Load (6 sites) | Single 500 MW DC |
|---|---|---|
| Hours of curtailment | 4 - 166 hours | 0 - 35 hours |
| Percent of time | 0.05% - 1.89% | 0.0 - 0.4% |
| MWh of curtailment | 674 - 24,628 MWh | 0 - 2,299 MWh |

APPENDIX F

# Key Visuals

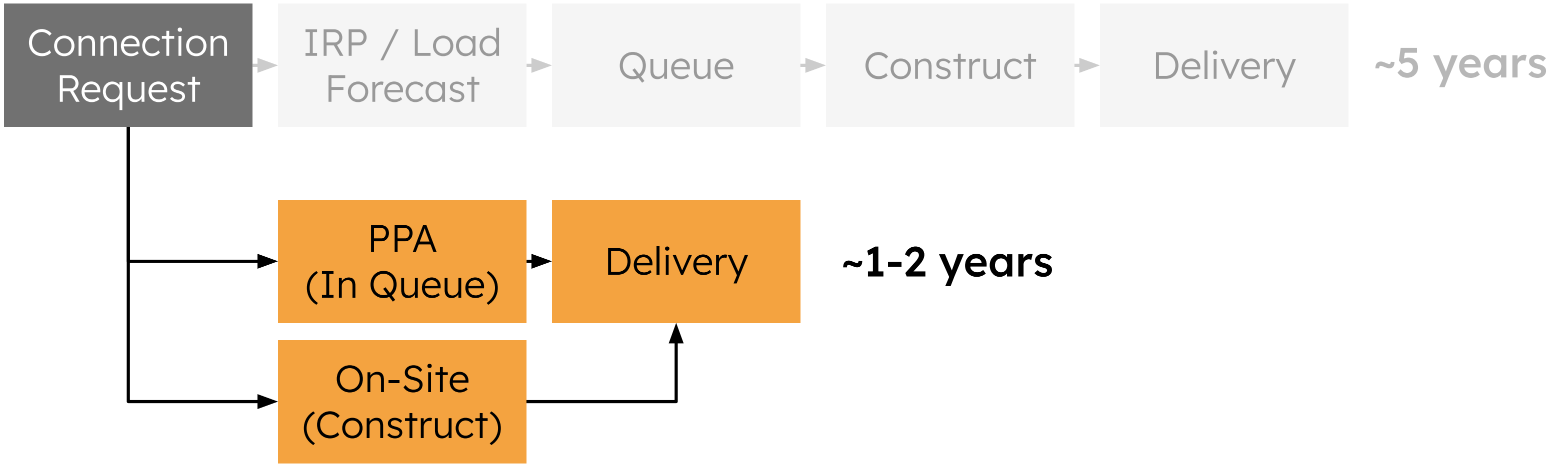
(Larger Versions)

# A flexible connection enables the data center to continue operating unaffected when the grid is constrained, by using local resources

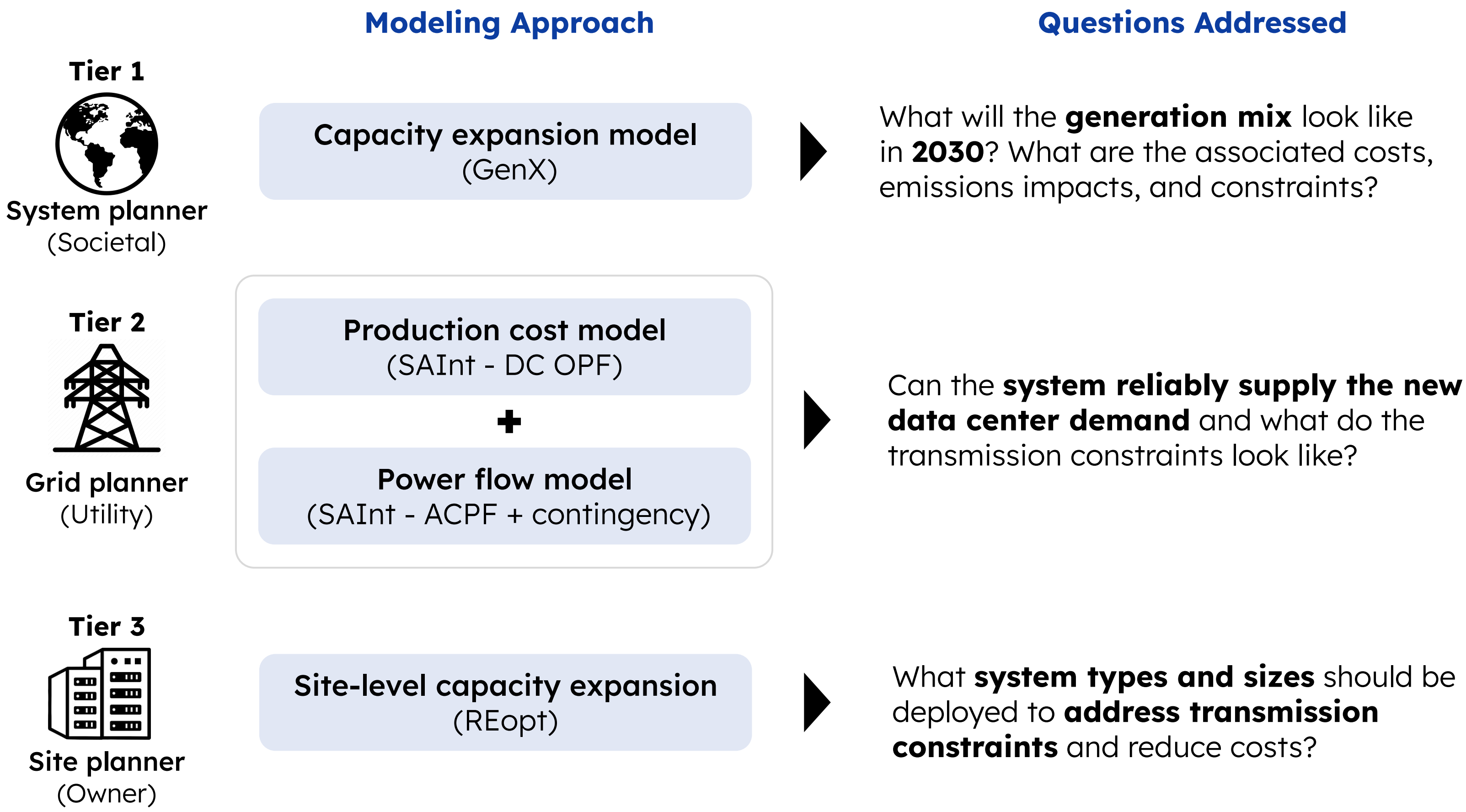



Approved connection is the contractually provided level of service, inclusive of both firm and conditional firm portions. Local generation or demand flexibility refers to on-site or nearby resources that generate on-site power or reduce demand below the constraint point. Grid capacity refers to the amount of power that can be delivered at a moment in time, inclusive of generation and transmission constraints.

# A bring-your-own capacity (BYOC) tariff addresses generation capacity constraints more quickly by procuring or building new capacity directly

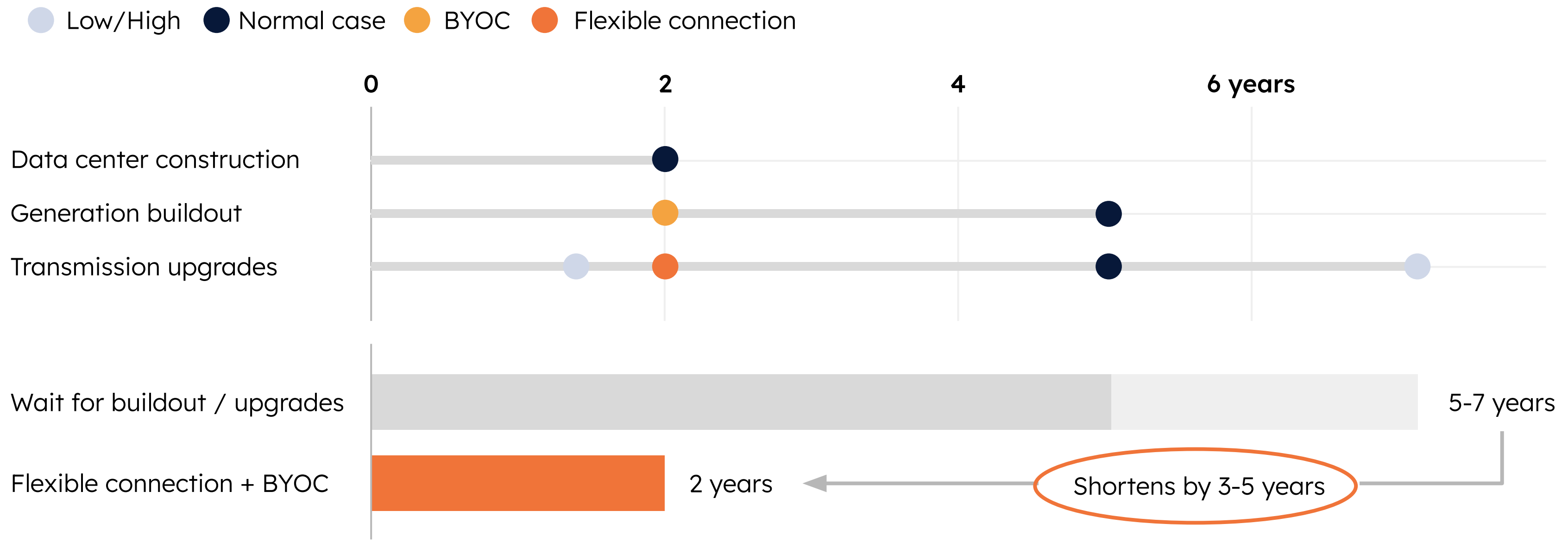



This represents a simplified, illustrative model of bring-your-own capacity. Eligible PPA resources are be limited to those that can be accredited by the ISO/RTO or relevant utility – including locational requirements based on regional supply needs. Note: Bring Your Own Generation (BYOG) constructs offer a parallel structure for data centers to bilaterally procure deliverable energy supply to match their demand, and can be paired with BYOC contracts to procure accredited capacity and delivered, time-matched energy.



Modeling Approach
Questions Addressed
Tier 1
System planner
(Societal)
Capacity expansion model
(GenX)
What will the generation mix look like in 2030? What are the associated costs, emissions impacts, and constraints?
Tier 2
Grid planner
(Utility)
Production cost model
(SAInt - DC OPF)
+
Power flow model
(SAInt - ACPF + contingency)
Can the system reliably supply the new data center demand and what do the transmission constraints look like?
Tier 3
Site planner
(Owner)
Site-level capacity expansion
(REopt)
What system types and sizes should be deployed to address transmission constraints and reduce costs?

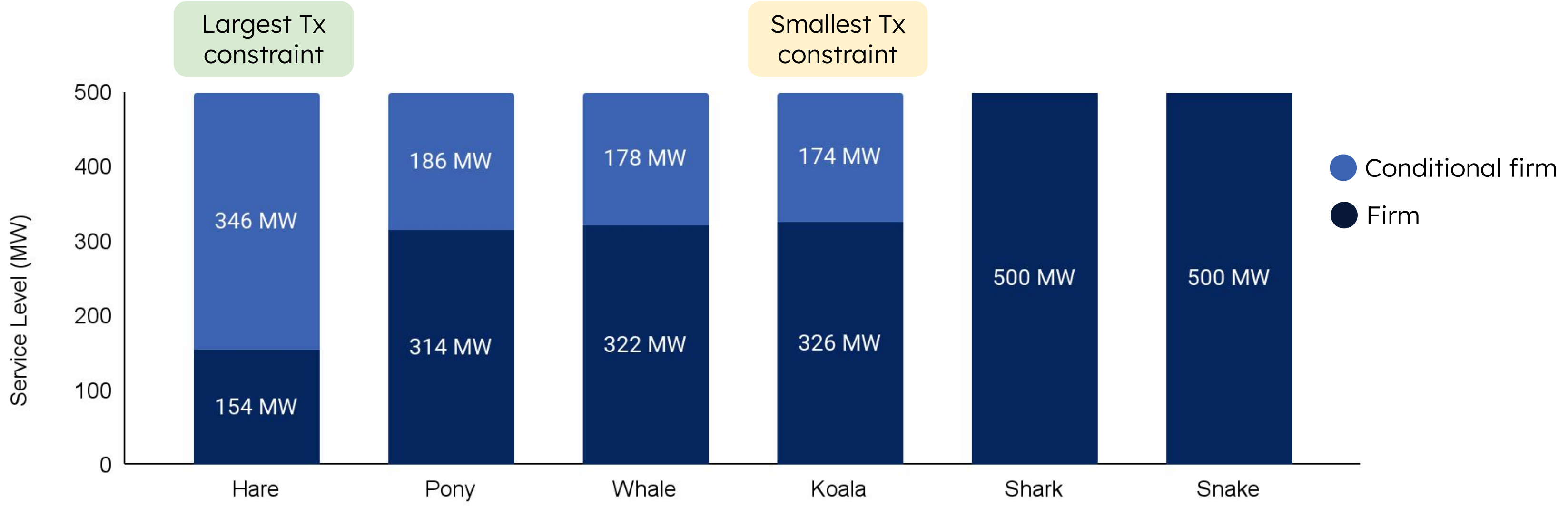
# Flexible connection and bring your own capacity (BYOC) shorten the wait for a data center grid connection by 3-5 years




Normal and high cases assume major transmission upgrades (e.g. new 230 kV or higher lines, significant reconductoring of lines) are required. Low case assumes extension of MV transmission and/or development of a new or retrofitted substation. Normal case for generation buildout assumes a new generation resource must navigate the PJM interconnection queue (start to finish).

Sources: U.S. Department of Energy Transmission Impact Assessment, Bloomberg, primary industry interviews

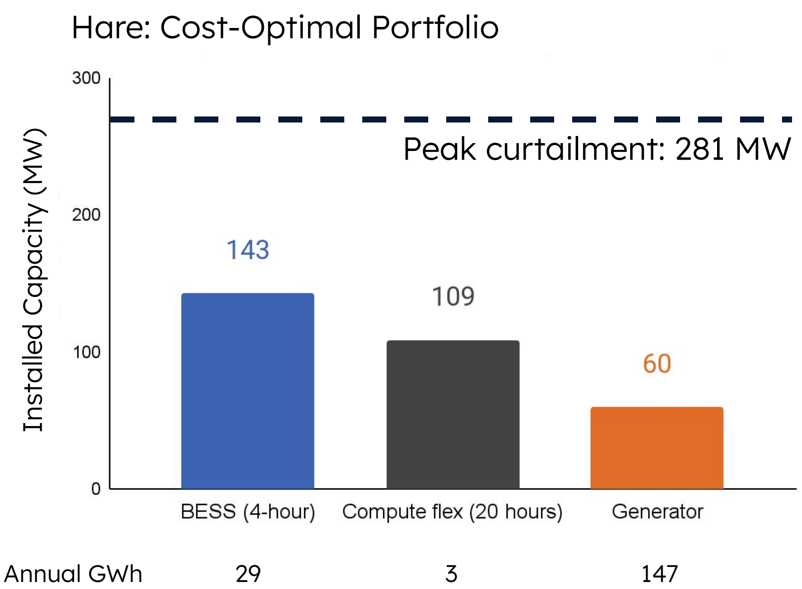
# Across all sites, grid power remained available for more than 99% of all hours in the year, with local resources dispatched for only 40 - 70 hours annually

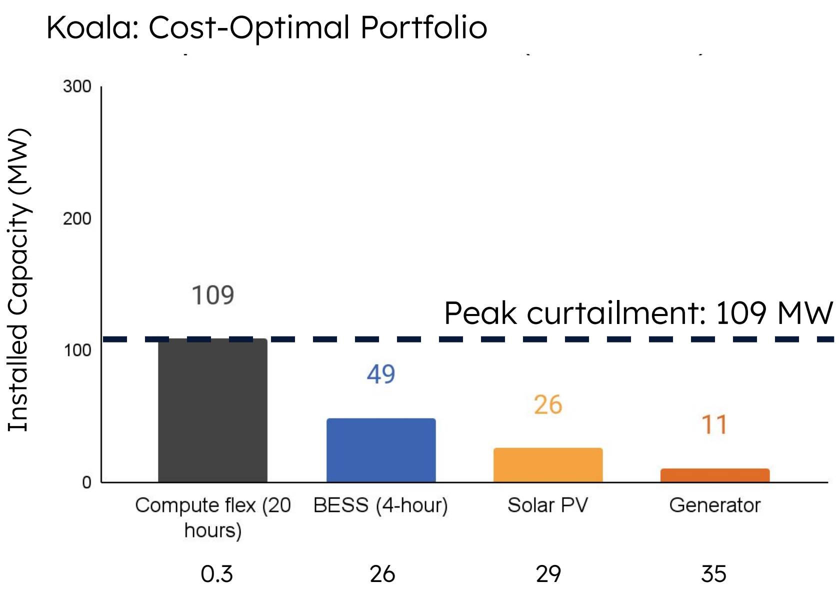



| | Hare | Pony | Whale | Koala | Shark | Snake |
|---|---|---|---|---|---|---|
| Time to connect | 2 years | 2 years | 2 years | 2 years | 2 years | 2 years |
| Transmission curtailment | ~35 hours | ~13 hours | ~11 hours | ~7 hours | 0 hours | 0 hours |
| Grid availability | >99% | >99% | >99% | >99% | >99% | >99% |
| Annual curtailment | ~67 hours | ~45 hours | ~43 hours | ~39 hours | ~32 hours | ~32 hours |

*Annual curtailment includes transmission curtailment + ~32 hours of estimated generation curtailment for all sites*

# On-Site Resources: Cost-optimal portfolios alleviate local transmission constraints and optimize bill savings for the data center



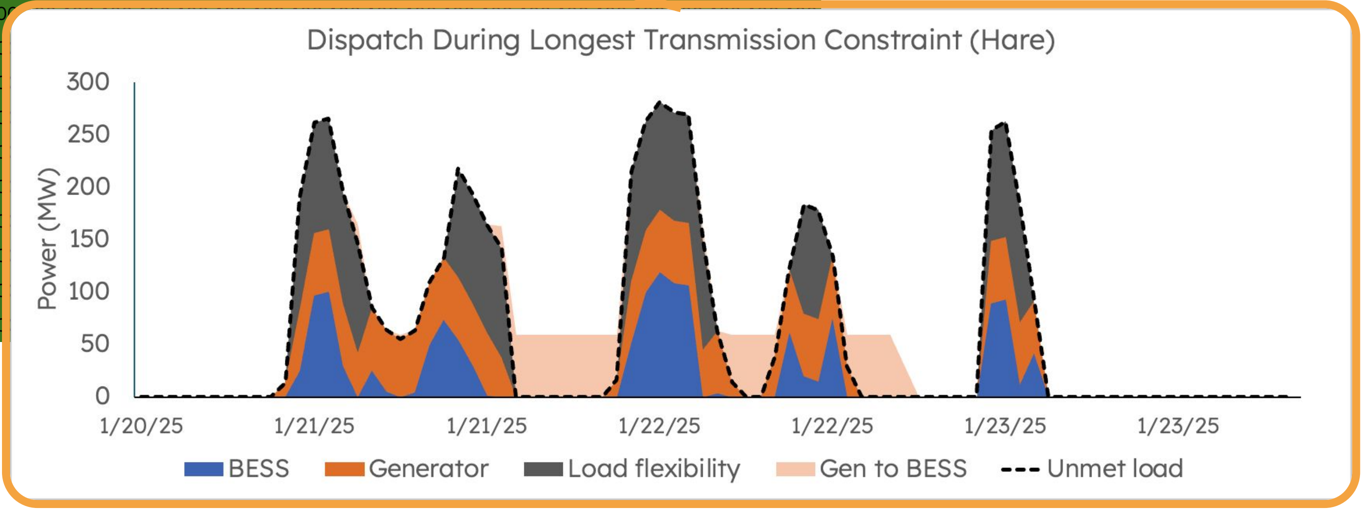




Analysis considered BESS, load flexibility (20 hours), solar PV, and natural gas generators as available on-site technologies. Annual GWh represents the GWh served by that resource (out of ~3,507 GWh of total annual demand for the data center). The cost-optimal portfolios include the resources required to meet the peak transmission constraint as well as optimize bill savings for the site.

# Grid power remains available >99% of the year; on-site or co-located resources are dispatched 40-70 hours annually to manage grid constraints

Daily minimum deliverable power (% of nameplate) – based on transmission capacity (Hare)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 47 | 44 | 48 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| Feb | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | | | |
| Mar | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Apr | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| May | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Jun | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Jul | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Aug | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Sep | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Oct | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Nov | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |
| Dec | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |




Dispatch of on-site resources during longest transmission grid constraint (Hare)

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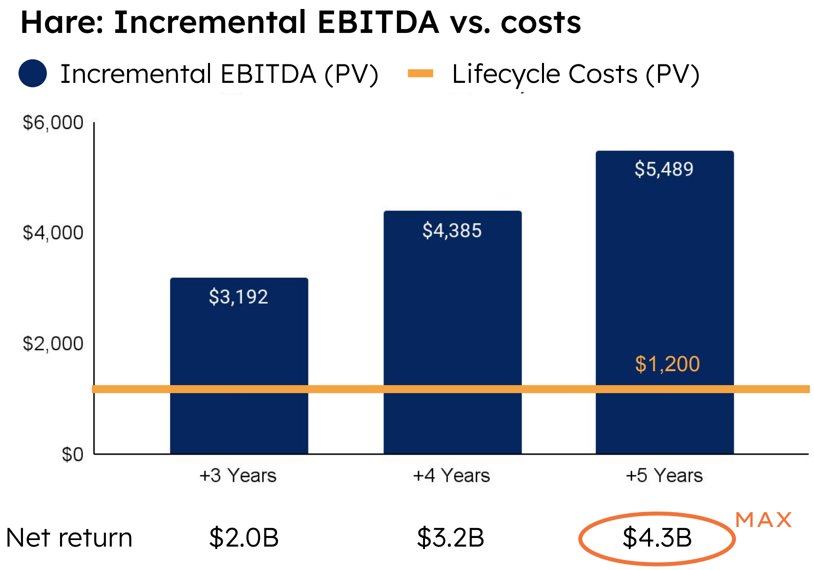
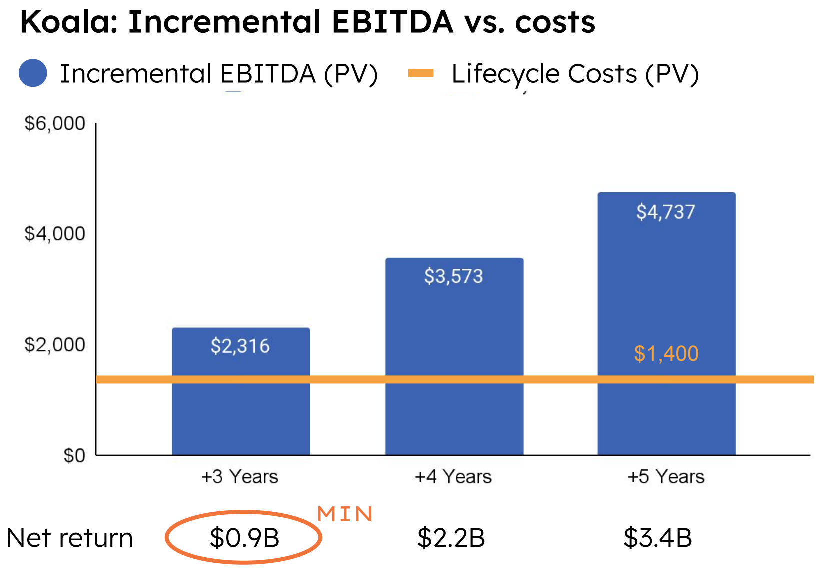
# Across studied sites, incremental EBITDA outweighs additional lifecycle costs by $0.9 billion to $4.3 billion for flexible connection + BYOC model



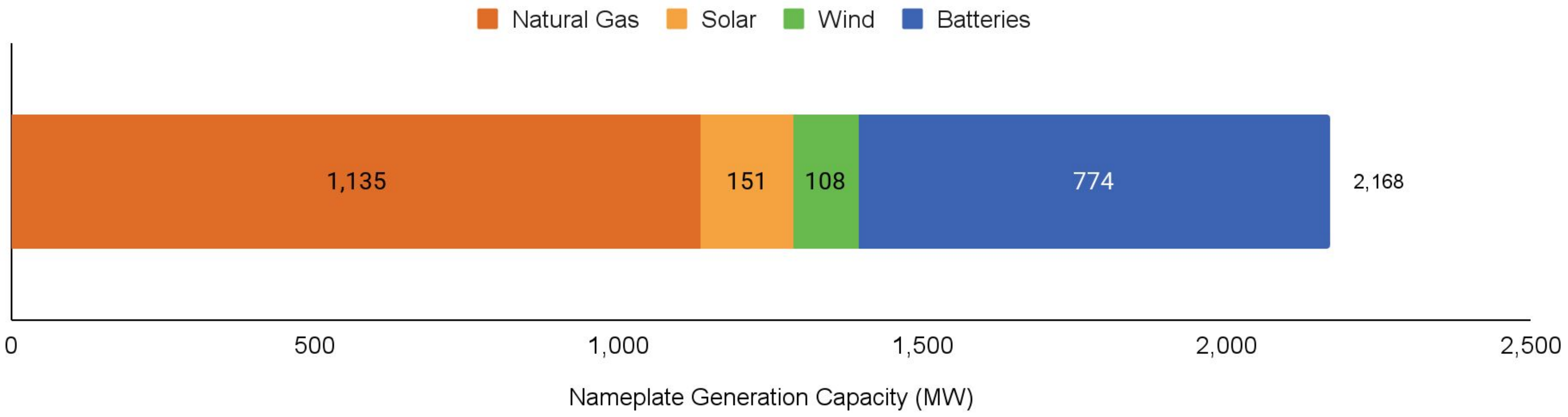

All values are present value (PV) based on 8% discount rate. Incremental EBITDA assumes $8M in annual revenue per MW and 45% EBITDA margin. The two sites were selected based on their status as the "bookends" with the largest (Hare) and smallest (Koala) transmission constraints. Incremental EBITDA assumes 500 MW is connected in Year 2 (when data center construction concludes) and is calculated as the difference between 500 MW and the available firm power for the site assuming generation constraints are alleviated in the final 2 years, allowing for firm service up to the transmission constraint. Incremental lifecycle costs includes the capital and operating costs for on-site resources required to enable flexible connections as well as the incremental costs of off-site PPAs and on-site resources required to enable BYOC models.

# Faster speed to power for a 500 MW data center drives incremental EBITDA while incurring add'l lifecycle costs; positive net returns with 2-5 years of gain

| **Net Returns ($B)** (EBITDA - Lifecycle Costs, Average of 2 Sites) | | Speed to Power Gains | | | | |
|---|---|---|---|---|---|---|
| | | +1 Year | +2 Years | +3 Years | +4 Years | +5 Years |
| Revenue Per MW | **Low** ($4M per MW) | -$0.9 | -$0.6 | +$0.1 | +$0.7 | +$1.3 |
| | **Median** ($8M per MW) | -$0.6 | +$0.1 | +$1.5 | +$2.7 | +$3.8 |
| | **High** ($12M per MW) | -$0.2 | +$0.9 | +$2.8 | +$4.7 | +$6.4 |

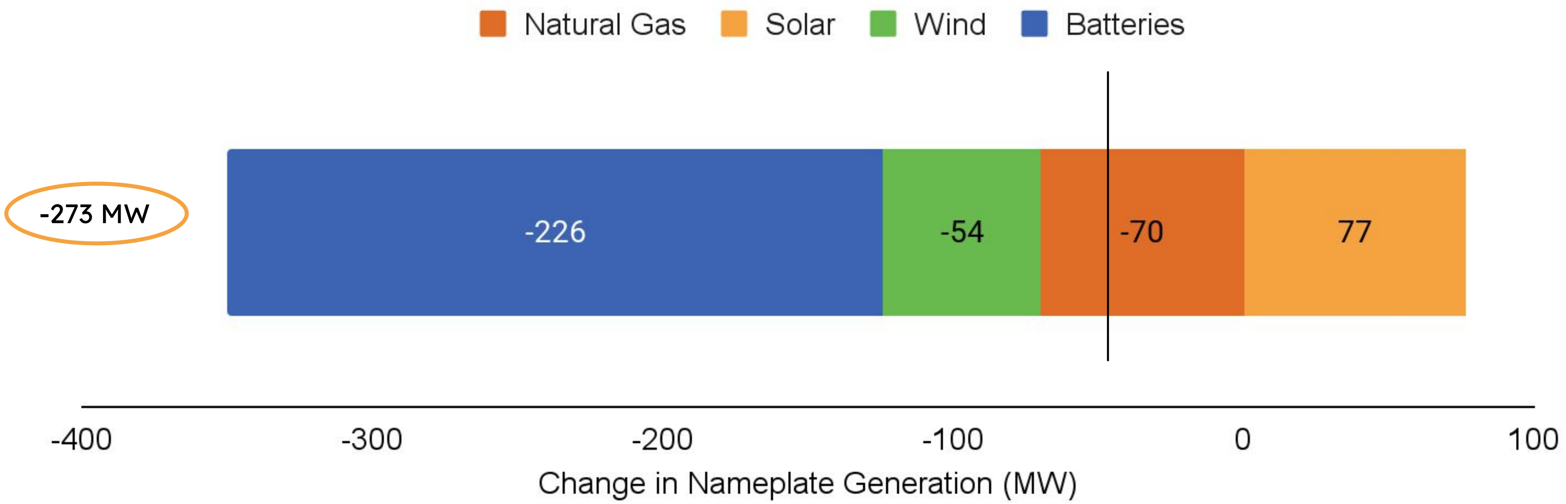
All values are present value (PV) based on 8% discount rate. Incremental EBITDA assumes $4M (low) to $12M (high) in annual revenue per MW and 45% EBITDA margin. All values are averages across the two bookend sites (Hare, Koala). Incremental EBITDA assumes 500 MW is connected in Year 2 (when data center construction concludes) and is calculated as the difference between 500 MW and the available firm power for the site assuming generation constraints are alleviated in the final 2 years, allowing for firm service up to the transmission constraint. Incremental lifecycle costs includes the capital and operating costs for on-site resources required to enable flexible connections as well as the incremental costs of off-site PPAs and on-site resources required to enable BYOC models.

# For each GW of new demand, GenX found that PJM would build 2.2 GW of nameplate generation capacity – mostly natural gas and BESS



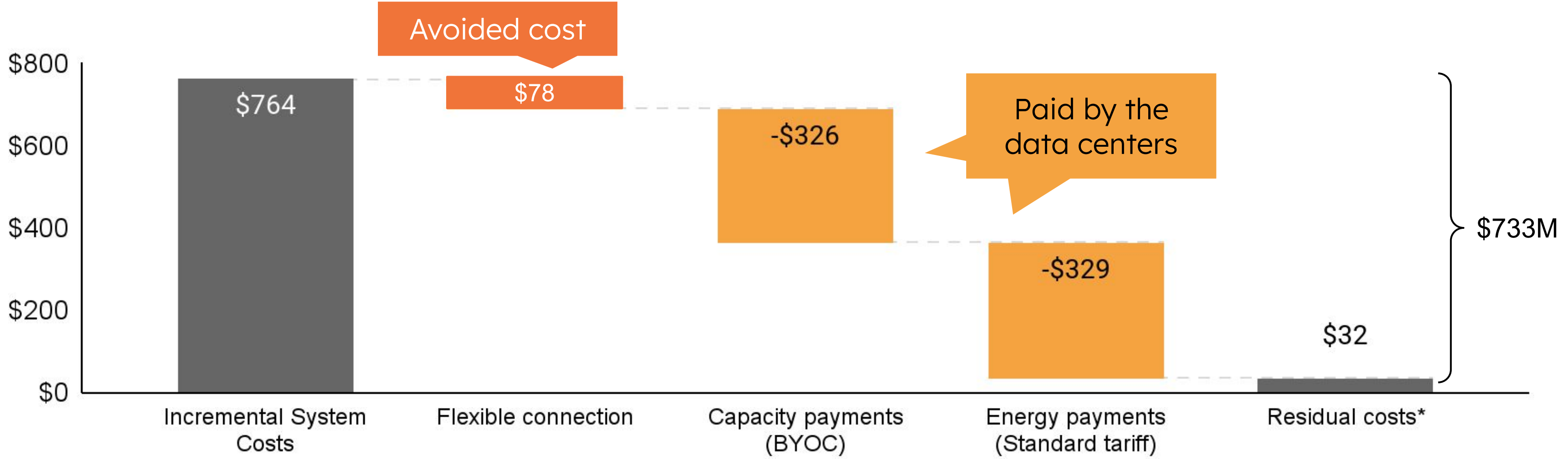

Based on +11.8 GW of data center demand growth in PJM between 2025-2030, in excess of 23 GW of baseline load growth and -20 GW of retirements.

# Flexible connection avoids 273 MW of new capacity per GW of incremental data center demand, primarily BESS




Assumes 20% conditional firm service, 80% firm service. Based on comparison to baseline scenario with 100% firm service. Applied to 11.8 GW of incremental data center demand (2026-2030).

# With flexible connections and BYOC, a data center covers ~100% of incremental system costs, ensuring costs are not shifted to other electricity customers.

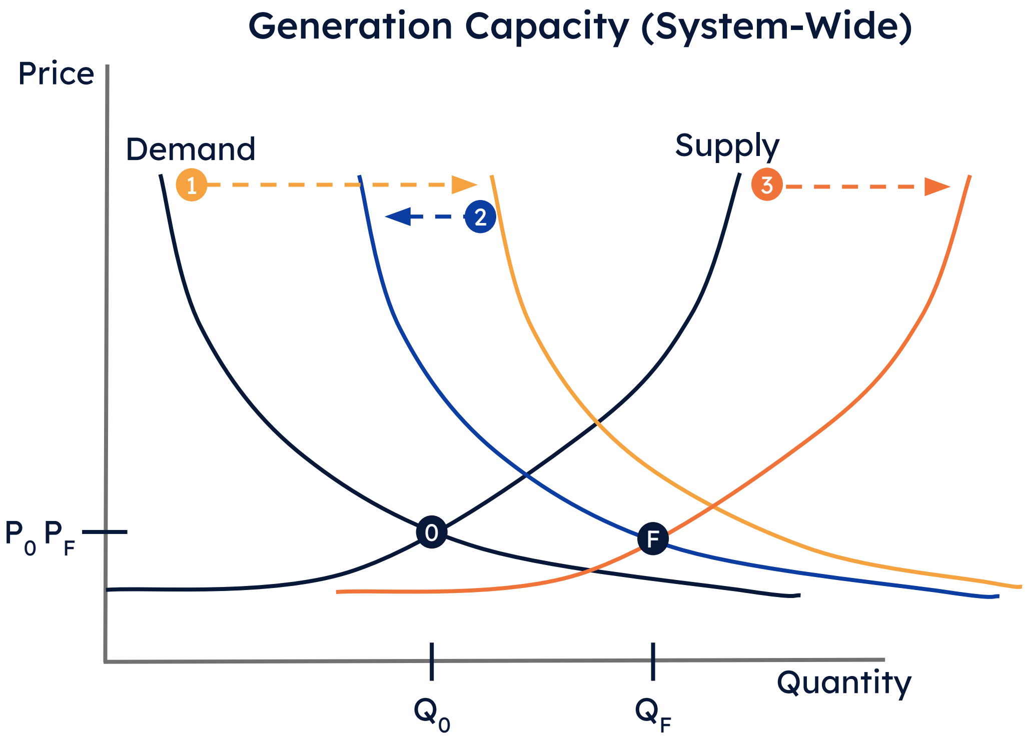



*Findings included 100% +/-5% cost recovery (e.g. 95-105%) across scenarios representing multiple levels of data center demand and flexibility. The 20% flexibility ("Flex20") scenario with baseline demand (represented above) results in $32M (~4%) residual costs. Residual costs arise from non-linearities in supply and demand curves, where GenX prices imperfectly align with system cost changes.

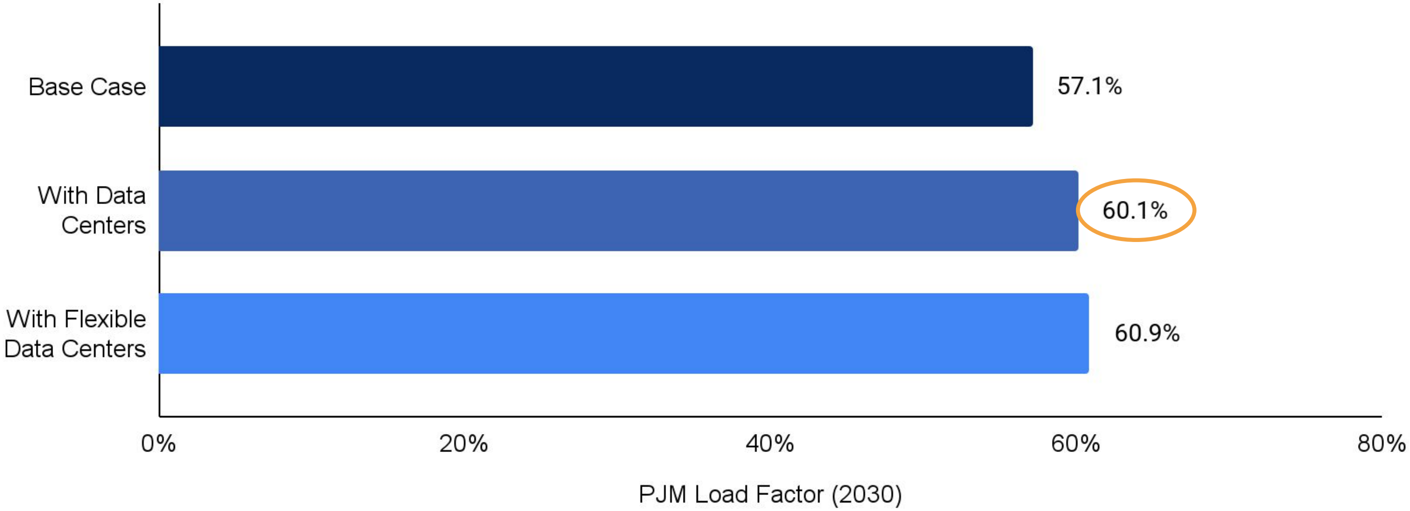
# BYOC boosts supply to offset higher demand; no change to price

**Conceptual model:**

- 0 Initial clearing price (“low demand” case)
- 1 Incremental data centers cause demand to increase
- 2 Flexible connection causes demand to decrease
- 3 BYOC increases supply with inframarginal offer
- F Result = ↑demand, ↑supply no change in capacity price



# PJM's load factor increases from 57.1% to 60.1% with incremental data center load by 2030; may increase further with flexible grid connections




All values are PJM-wide and for 2030. Assumes average data center load factor of 80% with 100% firm service. Flexible data center refers to 20% conditional firm, 80% firm service, reducing firm capacity by 20% and increasing effective load factor to 95-100%

# Barriers To Implementing Flexible Connections & BYOC

1. Planning frameworks are built for always-available demand

2. Accreditation methods don't consistently define and value load modifying resources

3. Tariffs only allow firm or non-firm service—not a mix.

4. Transmission & resource adequacy commitments must be independent

# Seven Actions To Accelerate Progress

**FOR UTILITIES**

- Invest in advanced planning tools
- Publicly signal willingness to engage
- Develop and standardize parameters

**FOR ISO/RTOS**

- Expand access to conditional firm service

**FOR DEVELOPERS & UTILITIES**

- Launch large-scale pilot projects

**FOR REGULATORS & POLICYMAKERS**

- Modernize planning & accreditation frameworks
- Create standard requirements & guidance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