NY LSR Financial Options and Cost Analysis

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July 8th, 2015

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One consideration examined by the LSR policy options paper is the potential reduction of ratepayer costs by enabling efficient long-term financing

We performed financial modeling to assess the extent to which LSR policy options could help achieve this goal:

- Using the alternative procurement mechanisms discussed in the previous session, and

- Enabling NY projects to take advantage of innovative financing vehicles optimized for LSR such as YieldCos and Debt securitization

Roadmap of presentation

1. Options Analyzed and Key Modeling and Financial Assumptions
   - New Financial Vehicles
     - YieldCos
     - Debt Securitization
2. Results of Project-Level Cost Comparisons
3. Annual Expenditure and Collection Impacts

1. Options Analyzed and Key Modeling and Financial Assumptions

We considered three base procurement options

- **Reference (20-Year REC Contract)**
  - Current policy – 20-year fixed price Main Tier REC contract
- **Bundled PPA**
  - 20-year fixed price power purchase agreement (PPA) for bundled energy and RECs, either with a state-entity or an EDC
  - Possible remuneration of utilities for PPAs was not included, but remuneration of 1% increases the cost of a PPA by roughly $0.70-$1.00/MWh
  - Perfect Hedge CfD would have the same impact
- **Utility-Owned Generation (UOG)**
  - 100% utility ownership and rate-basing of an individual project
  - Based on FERC data, assume utility has the tax capacity to fully monetize tax credits

We considered how innovative financing vehicles could impact the relative costs of these options

- **YieldCos**
  - Publicly-traded company, growth-focused & cash-flow oriented business model with low cost of capital
  - Promise to deliver steady, increasing dividends by continued acquisition of accretive, long-term, fully contracted assets
  - 20-year REC-only contracts do not provide sufficient price certainty on their own to make YieldCo financing likely
  - Long-term sustainability of business model still unclear
- **Ratepayer Backed Bond (RBB) Securitization**
  - Finance project loans through liquid, high quality bonds whose repayment is funded by non-bypassable charge
  - Ratepayers assume the risk of project default, but save money overall as they pay less for the electricity from the project
  - Takes advantage of portfolio and counterparty diversification benefits to reduce cost of debt

We compared policy and financing options for a hypothetical 100 MW wind facility in Upstate NY

Category	Input
Project Costs	
Commercial Operations Date	January 1st, 2017
Installed Cost[1]	\$2,044 / kW
Fixed O&M[2] **(Year 1)**	\$70 / kW - yr (escalated at 2.5% annually)
Variable O&M (Year 1)	0.06¢ / KWh (escalated at 2.5% annually)
Project Capacity and Production	
Project Size	100 MW
Capacity Factor	35%
Project Useful Life	20 years
Taxes	
Federal Tax Rate (%)	35%
State Tax Rate (%)	6.5%
Revenue	
Market Prices[3]	NYISO CARIS 2014 Zone D Forecast, AEO 2015 High Oil & Gas Resource Case (Low Market Prices) and High Price Case (High Market Prices) for Upstate NY

[1] Assumed bid in 2015, with commercial operation date = 1/1/2017, Nominal \$, costs updated based on estimates of recent wind capital costs by LBNL

[2] Includes insurance, project management, property taxes and land lease/royalty.

[3] Note: The Market Price Forecast significantly impacts the modeling results. Prices were generated from GE-MAPS modeling for the NYISO's 2014 CARIS 2 study, the most current CARIS price projections available. The NYISO has started its 2015 CARIS 1 analysis, and updated draft prices (10 year projection) will be released in June 2015. The NYISO expects LBMP price projections from this analysis to be significantly lower than prices from the 2014 CARIS 2 study due to lower natural gas price and load forecast assumptions.

Our key financial and modeling assumptions

- **No PTC –** We do not assume Federal Production Tax Credit (PTC) extension unless otherwise indicated
- **Project Financing as default structure –** with project debt and sponsor equity
- **No Curtailment –** We assume PPAs and UOG projects are not curtailed or subject to curtailment
- **Production estimates optimistic –** Assume actual energy production is 4% below pre-construction projections
- **Historic utility capital costs as discount rate (6.85%) –** from after-tax utility capital costs during 2002-2007
- **Levered Tax Equity for PTC sensitivities –** Levered with project debt for apples-to-apples comparison
- **Savings from RBB securitization net of expected cost to ratepayers of covering project defaults net of recoveries**

We developed financial inputs using published estimates as well as spread/forward yield analysis

Financial Metrics	Reference (NYSERDA 20-yr REC)	Utility-Backed PPA	Utility-Owned Generation (UOG)
Equity Return Targets[a]			
Developer Target IRR	12.75%	12.75%	12.75%
Long Term Equity Target IRR	10.50%	8.75%	9.00%
YieldCo Target Equity IRR	n/a	8.00%	n/a
Tax Equity Sponsor IRR	16.75%	15.00%	n/a
Tax Equity YieldCo Sponsor IRR	n/a	14.00%	n/a
Tax Equity Investor IRR	14.75%	13.00%	n/a
Debt Financial Metrics			
Maximum Leverage	n/a	n/a	52%
Debt Term	18	18	20
Debt Costs / Fees	2.00%	2.00%	n/a
Debt Minimum DSCR (P90)[b]	1.25x	1.20x	n/a
Utility Debt Cost[c]	n/a	n/a	4.75%
RBB Securitized Debt Cost[d]	4.40%	4.40%	4.40%
YieldCo Corporate Debt Cost[e]	n/a	5.50%	n/a
Project Debt Cost[f]	6.25%	6.25%	n/a

a Equity and tax equity return targets are based on ranges in Mintz-Levin (2012).

b Minimum DSCR requirements are applied on annual P90 cash flows

c Utility debt cost was estimated based on the implied forward 20-year treasury yield in 2017 of 3.25% and a projected spread for A-rated utility bonds of 150bp based on recent historical spread data.

d RBB Securitized debt costs were estimated as AAA corporate bond yields – a spread of 35 bp over utility debt.

e YieldCo corporate debt costs were estimated as BBB corporate bond yields – a spread of 75bp over utility debt.

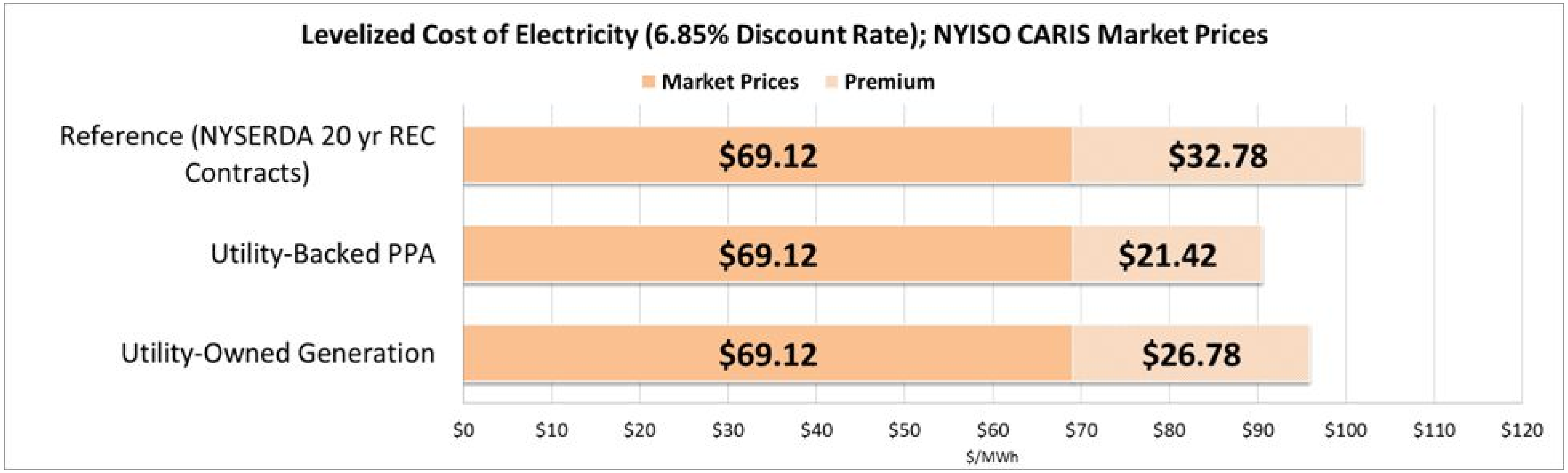
f Project debt costs were calculated using BBB corporate bond yields + 75bp for illiquidity and structuring.

2. Results of Project-Level Cost Comparisons

Summary of Project-Modeling Results

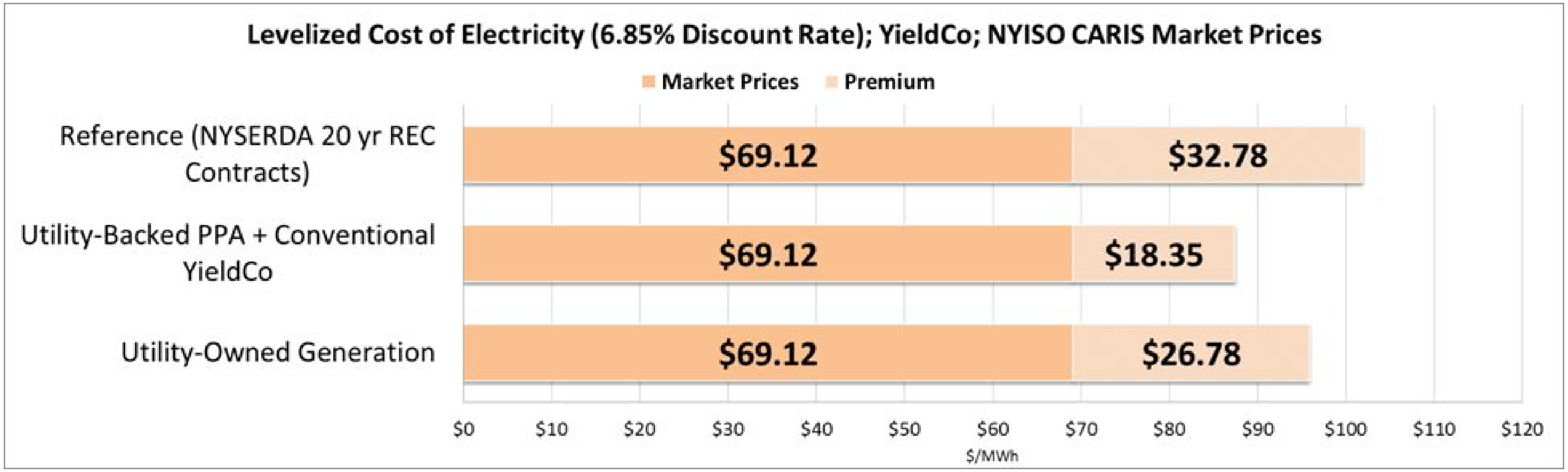
- **New procurement options can significantly reduce the premium required relative to current policy.**
  - Without PTC – Reference Case premium of $33/MWh. Utility PPAs reduce the premium by $11-12/MWh, ($14-15/MWh with YieldCos) while EDC Ownership can reduce it by $6/MWh.
  - With PTC – Reference Case premium of $26/MWh. Utility PPAs get it down to $8/MWh with tax equity, while EDCs eliminate the premium entirely. IPPs or YieldCos with tax capacity can do the same.
- **RenewCo can further reduce the premium by $1-5/MWh.**
  - This is net of $1/MWh cost of expected project defaults net recoveries.
  - Higher benefit when securitized debt displaces project-level debt.
- **With UOG, ratepayers bear the risk of wind production estimation uncertainty.**
- **The three options lead to different rate impact time profiles.**
  - UOG is expensive early on, but cheaper later due to low wind operating costs – and captures any (positive or negative) residual value after 20 years.

A PPA Can Cut the Required Premium for Wind by $11-12/MWh; UOG by $6/MWh



- No PTC extension assumed
- Premium is relative to discounted NYISO CARIS projected market prices

If the PPA enables YieldCo financing, this benefit could increase to $14-15/MWh

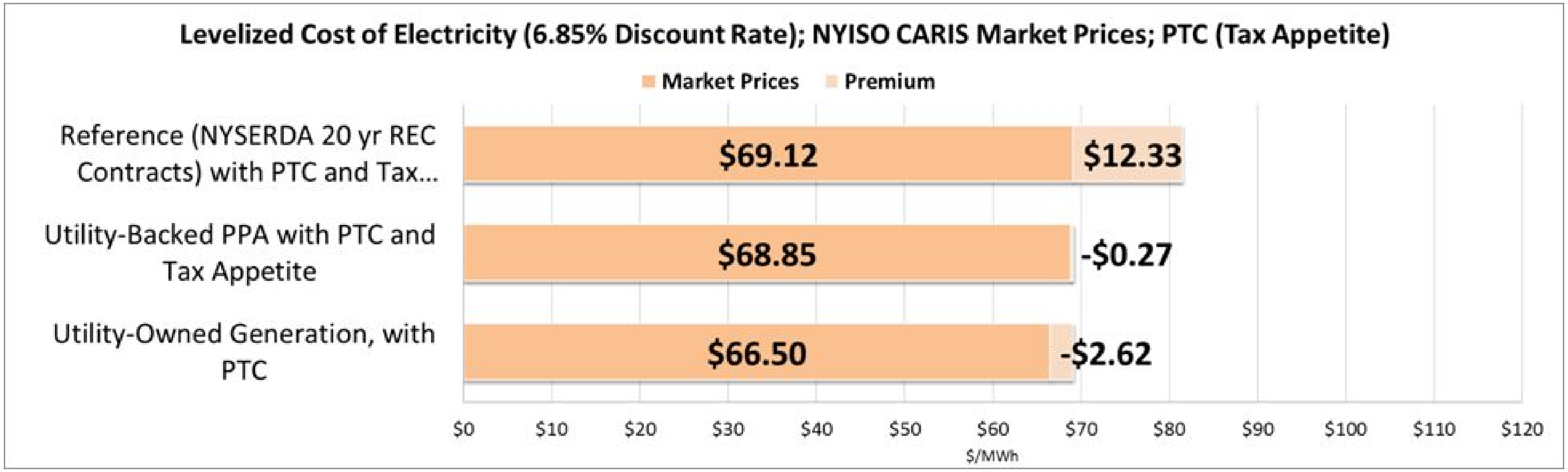


- No PTC extension assumed
- Premium is relative to discounted NYISO CARIS projected market prices

If PTC is extended, UOG is attractive if long-term investors in PPA/REC assets must use tax equity

- We assumed pass-through of PTC benefits to ratepayers
- FERC data suggest that NY utilities could monetize the tax benefits from as much as 1 GW of new wind in the near term
- For PPA and REC cases, we assumed sponsors use tax equity financing

But if long-term investors in assets with PPAs have tax appetite to monetize PTC, difference is small

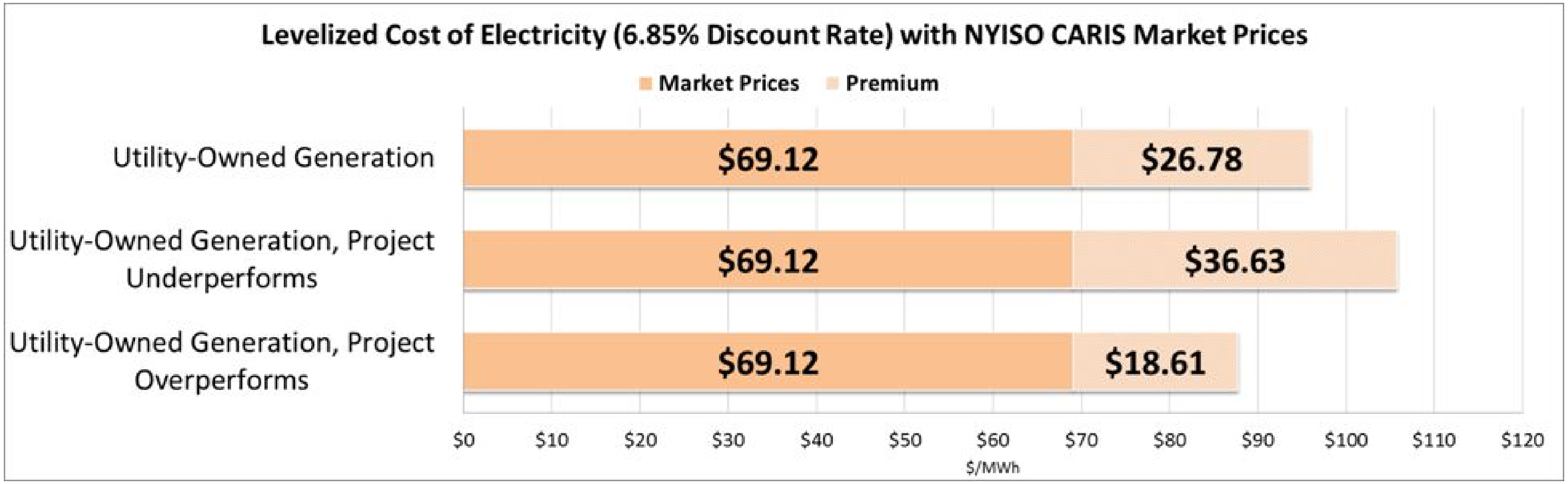


- Such long-term investors could include the unregulated affiliates of NY utilities

RBB Securitization can further reduce the premium by $1-5/MWh

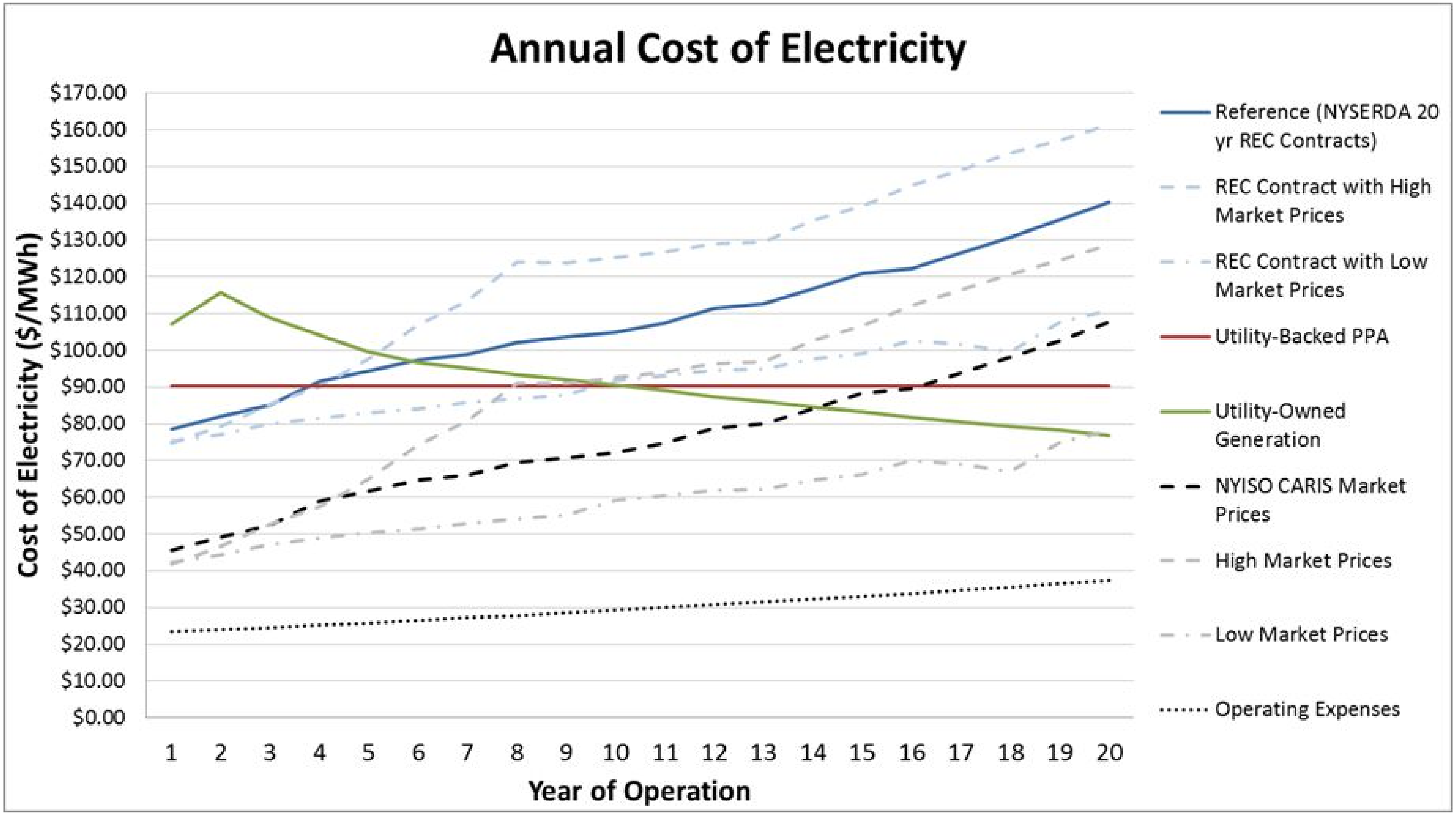
- This is net of the roughly $1/MWh cost of expected project defaults net of recoveries borne by ratepayers
- The benefit of securitized debt depends on the spread between project debt cost and securitized debt costs

With UOG, ratepayers bear the risk of wind estimation uncertainty (~$9/MWh uncertainty)



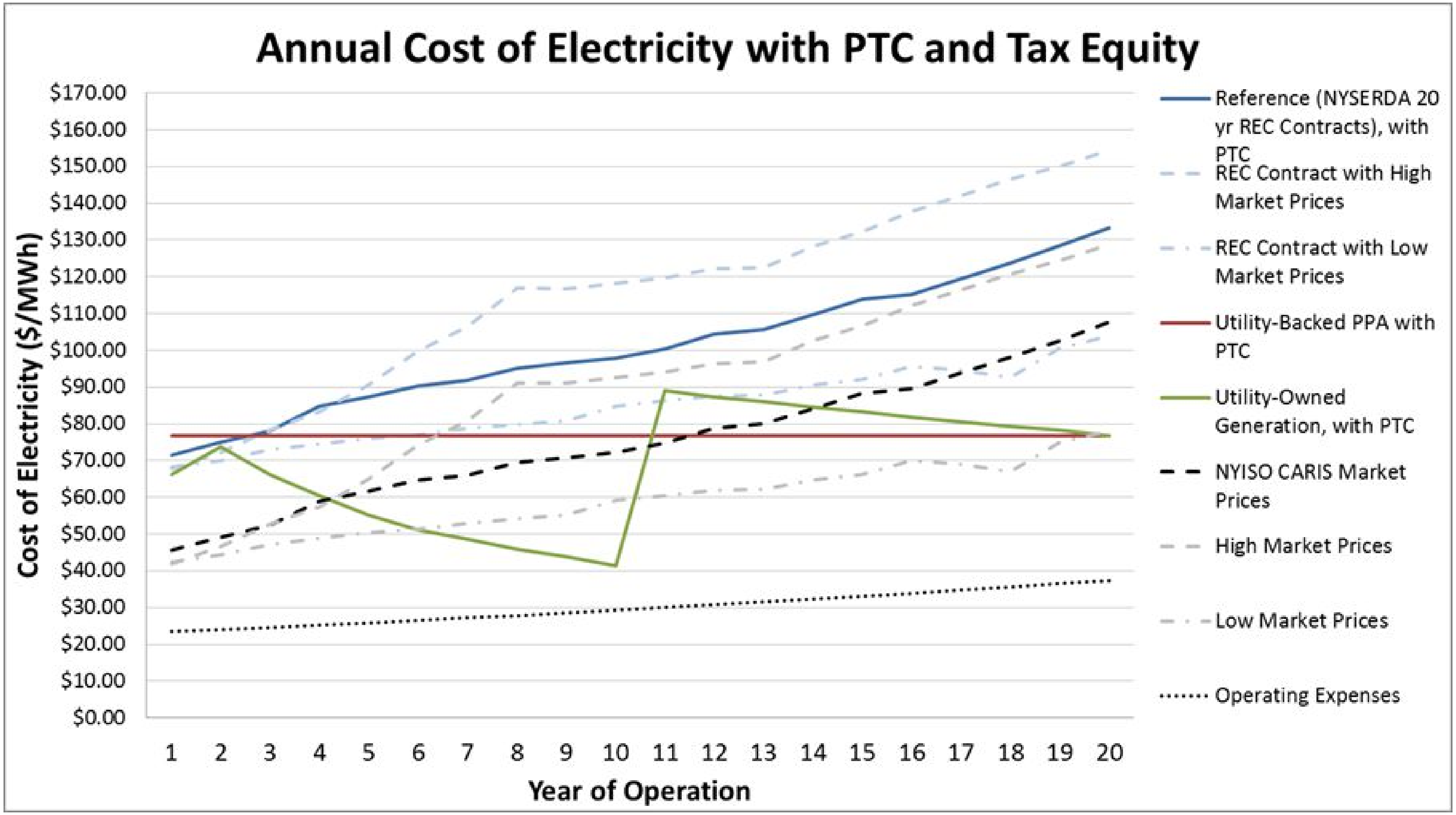
- Ratepayers are on the hook for compensating utility regardless of actual wind energy production – for PPA, owner bears that risk.
  - Average actual project production variance relative to pre-construction estimates is ~ 9%, with a systematic bias towards 4% underperformance.
  - The sensitivities above reflect the variance in levelized cost associated with that production variance.
- Further, we assessed the potential benefit of lower development risk with a utility acquisition, and found minimal impacts ($1.18/MWh with 9% developer IRR).

The time profile of ratepayer impacts significantly varies by option; UOG is expensive early



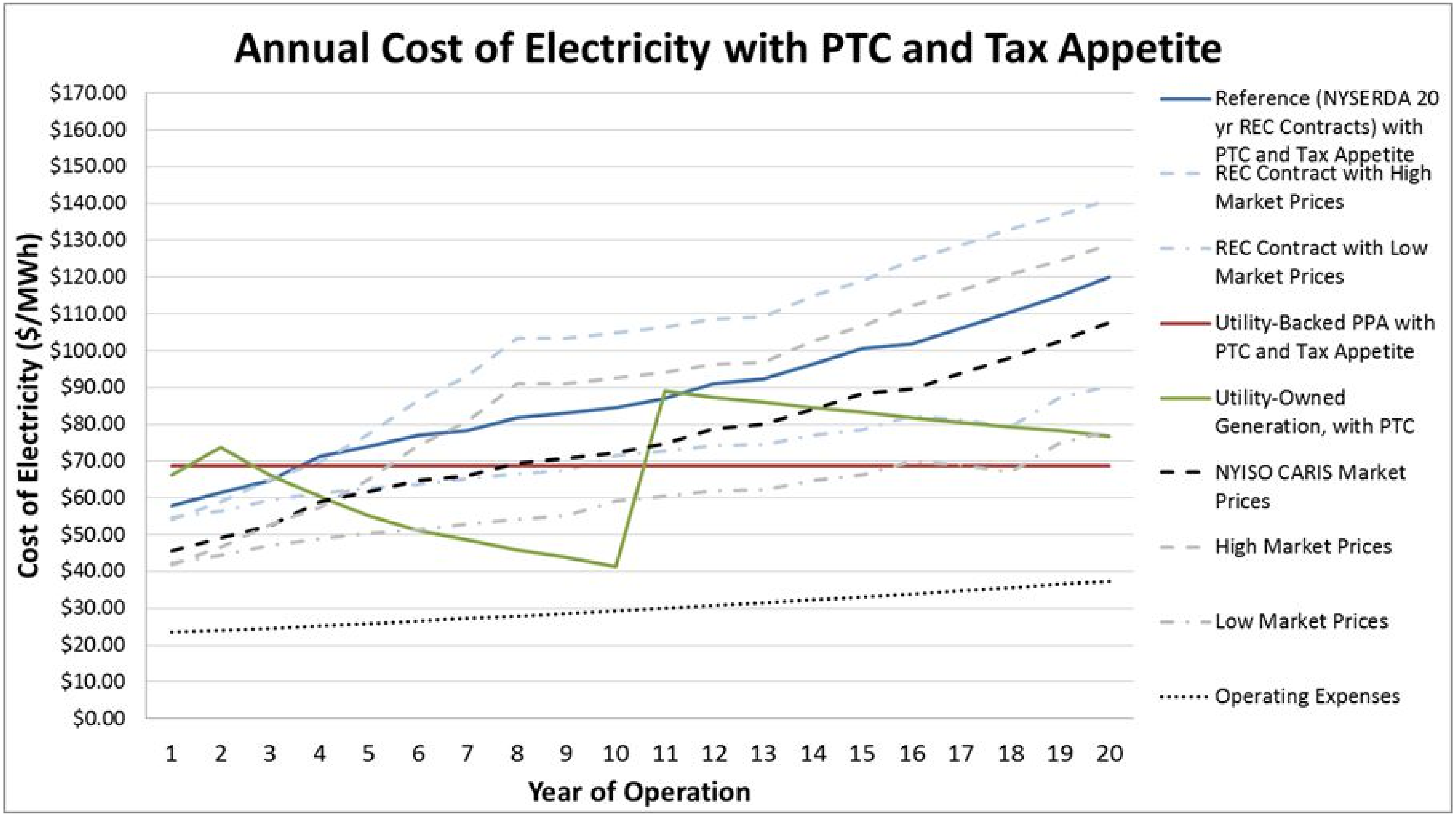
NOTE: With operating expenses well under half of projected market prices at the end of 20 years, EDC ownership has the potential up-side of providing terminal value at relatively low costs.

But the time profile of ratepayer costs for UOG with a PTC is actually quite attractive



NOTE: Time profile of EDC ownership costs is based on ratemaking treatment providing for credit of PTC during first 10 years of operation.

Though REC Contracts or PPAs with assets owned by investors with tax appetite can close the gap



NOTE: Time profile of EDC ownership costs is based on ratemaking treatment providing for credit of PTC during first 10 years of operation.

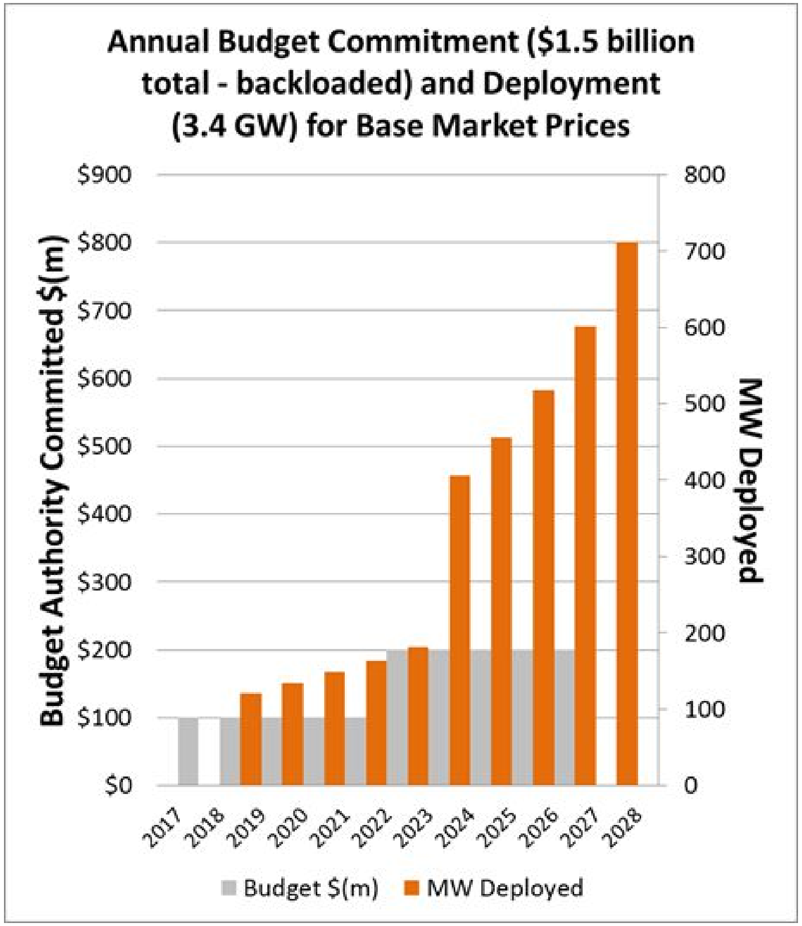
3. Annual Expenditure and Collection Impacts

How could new procurement options impact ratepayer collections and affect deployment?

- **PPAs provide lower, certain costs to ratepayers –** and do so over the long-term.
- **But costs relative to market prices is uncertain –** However, the PPA may end up costing more or less than procuring the energy at market prices
- **REC contracts lead to certain *incremental* costs –** Under current policy, it is rather the incremental costs above future market prices that is fixed and certain for each wind facility
- **This allows the use of a fixed ratepayer collection mechanism with deployment level certainty –** A fixed ratepayer collection mechanism is provided to pay those known incremental costs resulting in certain deployment at a fixed incremental cost
- **Procurement plans with a PPA need to be adjusted up or down to compensate for this –** Quantities in successive procurements can be adjusted up or down as needed to track desired cumulative expenditure level

How could new procurement options impact ratepayer collections and affect deployment?

- **We assess how this works with new procurement options –** We assess the deployment and cost impacts of a hypothetical fixed cumulative ratepayer investment of $1.5 billion over 10 years (comparable to historic levels)
- **We compare different market price scenarios –** We compared procurement mechanisms under base case and low future market price scenarios.
- **We use a back-loaded investment profile –** We considered a back-loaded investment of $100m/year committed for five years starting in 2019, and $200m/year for the next five years.



PPAs could procure 1-3 GW of wind over 10 years with a back-loaded $1.5 billion investment

$1.5 billion over 10 years for LSR Premiums	**Base Market Prices**			**Low Market Prices**		
	Deployment (GW)	Real Net Cost 2017 dollars (billions)	Nominal Net Cost (billions of dollars)	Deployment (GW)	Real Net Cost 2017 dollars (billions)	Nominal Net Cost (billions of dollars)
NYSERDA 20 Year REC	1.6	$1.1	$1.5	0.7	$1.1	$1.5
Utility-Backed 20-Year PPA	3.4	-$0.7	-$1.7	1.1	$1.1	$1.4
Utility-Owned Generation	2.1	-$0.2	-$0.8	1.0	$1.1	$1.4

- **Investment is used to cover incremental costs but isn't credited with future savings –** These funds were "spent-out" as collected from ratepayers through a flexible mechanism as needed to cover the *positive* differences between PPA price and market prices
- **We make simplified assumptions regarding future wind costs –** Assuming fixed nominal wind capital costs, escalating operating expenses and financing conditions based on forward yield curve analysis, we calculated the resulting deployment
- **This analysis did not attempt to assess the wind supply curve in NY.**

Ratepayer impacts of a $1.5 billion investment range from a cost of 0.7% to a 1% savings

$1.5 billion Planning Budget over 10 Years	Base Market Price Planning Scenario		Low Market Price Planning Scenario	
	Peak Savings (Excl. PSEG LI)	Peak Costs (Excl. PSEG LI)	Peak Savings (Excl. PSEG LI)	Peak Costs (Excl. PSEG LI)
NYSERDA 20 Year REC	n/a (n/a)	0.3% (0.3%)	n/a (n/a)	0.3% (0.3%)
Utility-Backed PPA	1.0% (1.2%)	0.7% (0.8%)	0.04% (0.05%)	0.4% (0.5%)
Utility-Owned Generation	0.7% (0.8%)	0.7% (0.8%)	0.07% (0.09%)	0.5% (0.6%)

- Peak costs under the utility-backed PPA option are expected to be approximately $150 million (in 2013 dollars) in 2028, or 0.7% of 2013 New York utility revenues (0.8% excluding PSEG LI)
- Peak savings of approximately $210 million (in 2013 dollars) or 1.0% (1.2% excluding PSEG LI) are realized much later, in 2043.
- In a low price scenario, the peak costs are 0.4% (0.5% excluding PSEG LI and the peak savings are 0.04% (0.05% excluding PSEG LI).