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Impacts of Investment Tax Credit on Public Schools in the United States: A Paired Analysis of Four Connecticut Projects

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ABSTRACT

Public schools adopt solar when the price meets their budgets and the financing is available. This study quantifies how the Investment Tax Credit affects both. Using four executed projects in Connecticut, two behind the meter and two front of the meter, we built paired cash flow models that hold technology, production, installed cost, loan terms, reserves, and a 15 percent levered IRR target constant while toggling the ITC between 40 percent and 0 percent. Production comes from HelioScope files that are used to bid on projects. Debt is sized to a fixed DSCR and an Excel VBA solver sets the PPA needed to meet the return. The comparison isolates the policy lever. Across all four sites, the required PPA rises by about 42 to 60 percent when the ITC is removed. Sponsor equity at commercial operation increases sharply as tax-equity proceeds disappear, while debt expands only modestly because coverage limits bind. Unlevered IRR and NPV margins move in the expected direction given the higher revenue requirement. The pattern is consistent across system sizes and metering configurations. The implication is practical for districts and program administrators. A 40 percent ITC functions as an affordability and bankability tool for school-sector PV, enabling lower PPAs and smaller equity checks at closing under otherwise identical conditions.

Key words: *Connecticut; distributed solar; education sector; Investment Tax Credit (ITC); K–12 public schools; renewable energy policy; rooftop photovoltaic (PV); power purchase agreement (PPA); United States; project finance*

I. INTRODUCTION

A. Background

This research and this topic has become increasingly important due to the recent necessary changes in both implementing and scrapping the Investment Tax Credits that is given to the Solar projects in the USA. School districts don't buy solar panels because they're shiny. They buy (or contract for) electricity that fits within a public budget, follows procurement rules, and does not distract from the mission of teaching kids. The investment tax credit (ITC) has been the economic hinge for making those numbers work in the United States. For more than a decade, tax credits have lowered the effective cost of capital for solar projects, allowed sponsors to bring in tax-equity dollars at commercial operation, and crucially, allowed public and non-profit hosts to access lower Power Purchase Agreement (PPA) prices than they otherwise could. NREL's finance documentation formalizes the mechanism: credits reduce required revenue and risk premia in the levelized cost of energy (LCOE) and rate-setting math, especially when paired with standard debt coverage constraints. [1][2]

Why this matters to schools is simple. Energy is one of the largest controllable operating costs in K-12, routinely cited in the $6–8 billion per year range, second only to salaries. Cutting a few cents per kilowatt-hour is real money for districts. [9][10] Solar on schools has therefore expanded rapidly. Generation180's most recent Brighter Future study estimates that solar energy on US K-12 campuses has more than quadrupled over the past decade and now reaches one in nine students nationally, evidence that when deals pencil, districts move. [8]

At the market level, strong credits have coincided with record deployment. SEIA/Wood Mackenzie report that the U.S. added roughly 50 GWdc of solar in 2024, with solar providing a dominant share of new capacity additions; multiple outlooks now attribute a sizable fraction of that momentum to the Inflation Reduction Act (IRA) credit suite and clarifying guidance on bonus adders. [4] The policy architecture is straightforward: a base ITC with potential bonus percentages to meet the prevailing wage and apprenticeship (PWA), domestic content, and energy community criteria - each documented in IRS / Treasury guidance. [13][14][15]

Connecticut offers a clean microcosm for studying school-sector implications because it pairs national tax policy with state programs that schools actually use. The Non-Residential Renewable Energy Solutions (NRES) tariff replaced legacy ZREC/LREC mechanisms and provides a predictable compensation framework for commercial and municipal PV, while the Connecticut Green Bank's Solar MAP(+) reduces transactional friction for towns and school districts. [16][17][18][19][20] Several districts have already leveraged these tools to deploy multi-site school portfolios with documented savings. [18]

This paper focuses on a single question framed by that context: What happens to real school-sector solar projects if the ITC is reduced from 40% to 0% while everything else—technology, production, costs, loan terms, and the investor return target—stays the same? We answer using four executed Connecticut projects (two FTM, two BTM) modeled under paired policy cases. The motivation is practical, not political: administrators and boards need to know how sensitive their PPA price and financing structure are to the presence or absence of an up-front credit.

B. Existing Evidence and Literature Review

The empirical link between incentives and solar deployment is no longer controversial: with credits, more projects clear the hurdle; without them, fewer do. But schools are not "average" customers, and the school-sector finance stack behaves differently from residential and large utility-scale solar. Three strands of literature matter here.

First, market-level deployment and pricing trends. LBNL's Tracking the Sun series documents multi-year declines in distributed-PV installed prices, the evolution of system characteristics, and the shifting balance between host-owned and third-party ownership (TPO) structures—context that helps separate cost learning from policy effects. The 2024 edition summarizes design and pricing data for 3.2 million systems through 2023, including non-residential rooftops akin to school projects. [5][6] SEIA/Wood Mackenzie's national summaries show the macro picture—record build and solar's rising share of new capacity—under incentive regimes with a base ITC and bonus adders. [4] LBNL's utility-scale work further illustrates how contract prices reflect financing conditions and policy settings across time. [7]

Second, finance mechanics and the pass-through of credits. NREL's Annual Technology Baseline (ATB) and finance notes spell out how tax credits lower LCOE/WACC under conventional debt coverage and depreciation assumptions. [1][2][3] Recent Berkeley Lab analysis takes it a step further for PPAs: when projects monetize credits, PPA prices tend to reflect that value, i.e., credits are passed through to buyers as lower contract rates than would otherwise be feasible. That pass-through is exactly what public institutions care about. [5] Prior sector work on TPO and PPAs has long emphasized this channel for non-taxable hosts such as school districts and universities. [11][12]

Third, school-specific energy and infrastructure baselines. DOE's Better Buildings and EPA resources put the stakes in budget terms—$8B/year in energy spend, often with deferred capital needs—while NASEO and GAO-cited reports document aging HVAC and facility systems that make utility bills and capital outlays harder to manage. [9][10] On the opportunity side, NREL's K-12 studies show that high-efficiency, PV-paired designs can fit inside "normal" school budgets and sometimes cost less over the lifecycle than conventional builds, a practical signal that schools can capture real value when the financing works. [11][12] Complementing the national view, Generation180's School Solar reports trace the expanding adoption curve across districts, including financing structures used by non-profits and municipalities. [8]

Connecticut's policy stack is a necessary part of the literature context because it establishes the non-federal levers that interact with the ITC in the real world. PURA's NRES program and the utilities' implementation materials describe the tariff categories, program caps, and transitions from legacy net-metering/REC regimes; the Green Bank's Solar MAP(+) lays out a turnkey process that many districts rely on to actually get from board resolution to COD. [16][17][18][19][20]

Taken together, the literature points toward a generalizable pattern: credits reduce required revenue and lower PPAs; non-taxable hosts rely on third-party financing to access those benefits; and schools are a large, cost-sensitive energy consumer with documented adoption momentum when projects can clear procurement with a competitive price. The specific quantitative effect of removing the ITC on school-sector PPAs, capital stacks, and equity at COD, however, is not yet exhaustively profiled in public work—especially using real, auditable project models.

C. Research Gap

Most prior studies either (1) trace market-level deployment as incentives ebb and flow, or (2) model generalized economics for representative systems. That's helpful background, but school boards don't approve "representative systems." They vote on specific PPAs for their roofs, tied to their debt coverage assumptions and their state programs. The gap we address is therefore practical and narrow:

1. Quantifying, with executed Connecticut projects, the PPA delta required to keep investor returns constant when the ITC moves from 40% to 0%;
2. Measuring how the capital stack reconfigures at COD—specifically, how much equity must replace missing tax-equity dollars and how far debt can increase under DSCR constraints; and
3. Doing this across FTM and BTM configurations that real districts use, inside the actual Connecticut program context (NRES, Solar MAP(+)) so results are more than a spreadsheet exercise. [16][17][18][19][20]

What the literature doesn't yet deliver—and what school administrators and state energy offices increasingly ask for—is a clean, within-project counterfactual where everything except the ITC is held constant. That is the gap this paper fills.

D. Research Objectives

To make the gap tractable for decision-makers, we converted it into a set of audit-friendly objectives:

- Isolate the ITC lever. For each of four executed Connecticut school-sector projects (two FTM, two BTM), hold constant the PV design (DC/AC size, Year-1 production, degradation), installed cost ($/W and total), soft costs, O&M, interconnection, loan tenor and coupon, reserve funding, and analysis horizon. Then vary only the ITC from 40% to 0% under identical modeling conventions. (Finance conventions follow NREL ATB definitions.) [1][2][3]
- Keep the return target fixed. Maintain a 15% levered IRR (LIRR) target in both policy cases and allow the PPA to solve endogenously to reach that target, as is typical in sponsor models and PPA negotiations. This pins down the host-facing price impact of policy.

- Measure the capital-stack response. Record equity at COD, tax-equity proceeds (if any), and debt. Report the equity share of total sources and outturn DSCR in each run to show what lenders are willing to fund under coverage constraints. (Recent LBNL work on pass-through provides an external check that lower required revenue under credits typically shows up as lower PPAs.) [5][11][12]
- Report host-relevant diagnostics. In addition to solved PPAs, present transparent diagnostics—unlevered IRR (ULIRR), "cash available to the SPV," and NPV margin—alongside interpretive cautions so readers don't confuse developer cash metrics with host value. The goal is to give districts the full picture they'll encounter in negotiations without burying them in jargon.
- Document external validity constraints. Tie each result back to the specific Connecticut program setting—NRES tariff rules and the Green Bank's MAP(+) process—to clarify where the conclusions travel easily (any DSCR-based, third-party financed school PV) and where they need re-calibration (regions with different tariffs, interconnection costs, or storage adders). [16][17][18][19][20]

E. Scope and Limitations

The study examines four school sector rooftop photovoltaic cases executed in Connecticut: two front-of-the-meter cases (FTM roof lease style) and two behind-the-meter cases (BTM bill offset). All four were engineered using standard nonresidential PV design workflows; Year-1 production and degradation are fixed from these models. Installed cost, soft costs, O&M, and interconnection are taken directly from the files. Financing assumptions (loan tenor, coupon, reserves, and fees) reflect typical school-sector sponsor underwriting; DSCR-based debt sizing is used in both policy cases. The analysis horizon is 20 years, a common offtake term in school PPAs. The only lever toggled between the paired runs is the ITC (40% vs. 0%). NRES/utility rules and Green Bank MAP(+) materials provide the state program context in which these deals live. [16][17][18][19][20]

Four cases do not make a census. Magnitudes will vary with regional tariffs, roof age/structural scope, interconnection queue conditions, and the presence of storage or additional revenue (SRECs, clean-peak, etc.). The 15% LIRR target is used for comparability; sponsors with different hurdles will solve to different absolute PPAs even if the direction of the ITC effect is unchanged. We restrict ourselves to rooftop projects; ground-mounts, canopies, and community solar under school subscription programs raise different siting and tariff questions. We also do not model direct pay/transferability in this core comparison; our purpose is to isolate the arithmetic of with-credit vs. without-credit under otherwise fixed terms. Finally, while the Brighter Future and Tracking the Sun datasets are comprehensive at the national level, Connecticut-specific adoption numbers are still best read through state sources (PURA, utility program reports, CT Green Bank portfolios) rather than generalized national means. [5][8][16][17][18][19][20]

F. Significance of the Study

Public education budgets are tight, needs are high, and energy is a line item that can either siphon funds from classrooms or free them up. The contribution of this paper is not that "incentives are good" in the abstract. The contribution is that we pin down, with auditable models from real Connecticut school projects, how much the ITC matters for the two things that decide school solar deals:

- The price schools must pay (required PPA to meet a fixed return), and;
- The capital stack schools' partners must assemble at COD (how much equity has to replace missing tax-equity, and how far debt can go under DSCR constraints).

By reporting both FTM and BTM configurations, we cover the two dominant ways districts procure solar today. By holding everything except the ITC constant, we eliminate the usual confounders and present a clean, within-project counterfactual that boards, superintendents, and energy offices can actually use. And by situating the analysis inside Connecticut's NRES/MAP(+) ecosystem—while tying it to national evidence on pricing, TPO, and pass-through—we give a template that other states can adapt without guessing. [4][5][8][11][12][16][17][18][19][20]

The stakes are larger than four roofs in one state. SEIA/Wood Mackenzie and Reuters coverage show solar commanding a dominant share of new U.S. capacity additions; Generation180 shows that school solar has scaled as the economics improved and processes matured. [4][8] The ITC has been a central part of that story—partly by attracting tax-equity capital, and partly by lowering PPAs through pass-through to public buyers. [5][11][12] If the objective is to let more districts in Connecticut—and across the U.S.—procure solar within their budget guardrails, the mechanism we quantify here is the one that matters most: with a 40% ITC, the same roofs, modules, and inverters require lower PPAs and less sponsor equity at COD than they do at 0%. That's not an opinion. It's the math of school-sector project finance, documented in the pages that follow.

II. Material and Methods

A. Materials: data sources and artifacts

We assembled complete financing workbooks, EPC quotes, and program documents for four executed Connecticut school-sector PV projects (two behind-the-meter, two front-of-the-meter): Tyrell School, Derby School, Dominican University, and Meriden Schools. Each project package contained several metrics. First, system design and production exports (array layout, losses, and Year-1 yield) from HelioScope; the tool's energy outputs are documented and benchmarked by NREL against measured systems. Second, EPC pricing (installed $/W and total capex), interconnection cost estimates, warranty/O&M budgets, and construction schedules from the developers and contractors. Third, financing term sheets from the energy-as-a-service (EaaS)/IPP counterparty and lender, including loan tenor, coupon, reserve requirements, and fees. And also, program documents for Connecticut's Non-Residential Renewable Energy Solutions (NRES) tariff that governed offtake rules for FTM/BTM cases. Federal credit mechanics and bonus-adder definitions were referenced from primary sources: NREL Annual Technology Baseline (ATB) finance documentation for LCOE/WACC conventions, and IRS/Treasury guidance on prevailing wage/apprenticeship, domestic content, and energy community provisions that determine eligibility for bonus ITC levels. These references were used to confirm modeling conventions, not to "qualify" individual projects (we fix the ITC setting by design—see IV.B).

For cross-checks on installed cost reasonableness and design parameters we consulted LBNL's Tracking the Sun series and Generation180's Brighter Future report on school solar deployment. These sources are not inputs to the model; they are reality checks to avoid using outlier assumptions.

B. Study design and identification strategy

We perform a paired counterfactual on each project: run the fully specified model twice—once with ITC = 40% and once with ITC = 0%—while holding constant every other parameter (capex, layout/production, O&M, interconnection, fees, debt tenor and rate, reserve policy, tax assumptions, and analysis horizon). The paired design eliminates confounders; any change in required PPA, capital stack, or coverage is attributable to the ITC setting. Because public school hosts are non-taxable, the project company (sponsor/EaaS) monetizes the ITC and passes value through to the PPA price. This is standard practice in third-party financed PV and is consistent with NREL/LBNL finance guidance. Rooftop PV only; no storage in the core comparison. Two FTM roof-lease style cases and two BTM bill-offset cases, all in Connecticut. Of note for replication: each project's Year-1 production (kWh) and degradation (0.5%/yr) are taken directly from HelioScope files used to build/bid the projects. Modeling platform and tools used:

- Excel 365 with VBA macros (Goal Seek + custom routines) for debt sizing and PPA solving.
- HelioScope for production modeling (fixed-tilt rooftop arrays); validation per NREL.
- Occasional SAM-style checks via ATB finance conventions (discounting, fixed charge elements), ensuring our LCOE/NPV math is consistent with public documentation.
- Program rules and eligibility checks referenced from PURA NRES materials.

All workbooks are version-controlled (date-stamped, with reviewer initials). Each scenario has a locked Inputs tab, a Sources & Uses tab, an Operating Model (monthly cash flows), and Ratios/Checks (DSCR, debt covenants, fee checks).

C. Financial structure and key assumptions (constant across both ITC cases)

- Analysis horizon: 20 years (primary results), matching typical school offtake terms under PPA/roof-lease structures.
- Discounting for XNPV metrics: project WACC derived from ATB finance conventions (we cite the method; the numeric value is set in the workbook and held constant across ITC cases).
- Debt: Term loan with 20-year amortization, fixed rate (per term sheet), quarterly debt service in the base runs. Debt advance rate = 80% of eligible basis; DSRA funded at closing per lender requirement.
- DSCR constraint: debt sized such that minimum annual DSCR during the first contract term meets or exceeds the lender threshold (>=1.35x in our base underwriting).
- Taxes & depreciation: Corporate tax rate and 5-year MACRS depreciation applied for the project company (host is non-taxable).
- Operating costs: O&M and insurance per EPC/warranty budgets; O&M escalator = 3%/yr (unless an EPC contract specifies a different escalator).
- Loan and fee inputs (construction interest, underwriting, const. insurance, appraisal, and ITC setup fees) taken directly from the term sheets in the project files.

Where bonus ITC eligibility was documented (e.g., energy community), the 40% case reflects the aggregate percentage shown in the project file; the 0% case zeros that lever by design. We did not re-determine eligibility under updated IRS notices; the goal is a clean with-credit vs. without-credit arithmetic, not a re-qualification exercise. IRS/Treasury references are cited to document what those terms mean.

D. Procedure

For each school, we compiled EPC contracts, interconnection budgets, and HelioScope exports; normalized all costs to a common decision date; verified that ITC basis equaled total eligible costs; and checked that HelioScope kWdc/kWac, loss assumptions, and Year-1 kWh matched the financial model (reconciling any design revisions). We then mapped each site to the correct Connecticut NRES category—FTM tariff or BTM/REC treatment—so the revenue line reflected the program actually governing the project. In Excel, the base financing model consists of a Sources-and-Uses schedule (EPC hard cost, soft costs, construction interest, reserves, fees) feeding a monthly operating model that computes PPA revenue (solved price × delivered kWh), subtracts O&M/insurance, forms EBITDA, applies taxes and MACRS, and produces cash available for debt service and distributions. A VBA routine sizes term debt: start with 80% advance rate on eligible basis, build amortization and DSRA, evaluate annual DSCRs, then iterate (bisection/goal-seek) until the minimum annual DSCR is within ±0.01× of the target; lock debt. A second VBA routine solves the starting PPA so the levered IRR to equity equals 15% with the host escalator held fixed. We run paired scenarios with all else constant: (i) ITC = 40%, inserting net ITC transfer proceeds at COD (after setup/appraisal/insurance fees), rerunning debt sizing, and re-solving the PPA; and (ii) ITC = 0%, zeroing ITC proceeds and repeating the same steps. For each run we record required PPA, ULIRR, NPV margin, debt at COD, equity at COD, any tax-equity/ITC proceeds, equity-to-project-cost ratio, and the DSCR profile, plus net cash to the SPV and XNPV diagnostics; results are reported as level values and as ITC-ON minus ITC-OFF deltas. QA/QC includes HelioScope to model parity on Year-1 kWh and degradation, Sources=Uses to the dollar, clean cash roll-forwards, DSCR at or above the covenant in both cases (without upsizing debt after the PPA solve), correct tax basis reduction when ITC is present, and reasonableness checks against public non-residential cost/O&M ranges and school-sector adoption stats, with program compliance verified against the NRES manual (tool conventions per NREL; production per HelioScope validation; cost/distribution ranges per LBNL; adoption context per Generation180; tariff rules per PURA).

E. Equations and metric definitions

Where possible, we align with ATB and standard project-finance notation so other analysts can reproduce the results in SAM, Python, or a different Excel model.

$$CFE\mathrm{t} = EBITDA\mathrm{t} - Taxes\mathrm{t} - Debt\ Service\mathrm{t} \pm \Delta Reserves\mathrm{t}$$

$$\text{Annual DSCR : DSCRy} = \frac{\sum_{t\in y} (\text{ EBITDAt } - \text{ Taxest })}{\sum_{t\in y} \text{ DebtServicet}}$$

$$\text{XNPV margin : } \frac{XNPV(\text{ Inflows }) - XNPV(\text{ Outflows })}{XNPV(\text{ Outflows })}$$

In the ITC-ON case we model a transfer of the credit at COD (consistent with IRA transferability), booking cash proceeds net of setup/appraisal/insurance fees. In alternative structures (partnership flip) the timing and economics differ, but the comparability principle is the same: the presence of an early-year benefit reduces required revenue and/or equity. IRS/Treasury sources document bonus-adder definitions; we fix the total ITC percentage per the project file.

Although the primary results are **paired point estimates**, we ran structured one-at-a-time sensitivities on:

- **Capex ±10%** (EPC ±$0.20–0.40/W depending on baseline).
- **Interest rate ±100 bps** (term loan coupon).
- **PPA escalator 0–2%/yr** (held constant within each pair).
- **O&M escalator 2–4%/yr**.
- **Degradation 0.3–0.7%/yr**.

For each sensitivity, the delta between ITC-ON and ITC-OFF remained in the same direction: higher required PPA and higher equity at COD in the ITC-OFF case. Magnitudes varied in proportion to capex and rates, which is expected under ATB-style LCOE mathematics.

III. Results

A. Purpose and design

This section reports empirical results from four executed educational rooftop PV projects—two front-of-the-meter (FTM: Tyrell School (A), Derby School (B)) and two behind-the-meter (BTM: Dominican University (C), Meriden Schools (D)). Each project is modeled under two policy counterfactuals: an ITC of 40% and ITC of 0%. To isolate the effect of the ITC, all technical and financial inputs unrelated to the credit are held constant across the paired runs: DC/AC capacity, Year-1 production and annual degradation, total installed cost ($/W and $), interconnection and soft costs, O&M, analysis term (20 years), loan tenor and coupon, fees and reserves, and solver conventions. The levered IRR (LIRR) target is fixed at 15% in both cases; the PPA price is solved endogenously to reach that target; and debt sizing follows the model's internal DSCR routine. Financial metric definitions (IRR, DSCR, LCOE framing) follow standard project-finance practice as documented by NREL's Annual Technology Baseline finance notes. [21]

Notation. Where dollar figures appear, they refer to nominal dollars at commercial operation date (COD). Percent changes are computed relative to the 40% ITC baseline for each project unless noted. All sources and uses balance at COD in each run; differences across runs arise from the ITC lever alone.

B. Project inputs and technical performance

	ITC 40%				ITC 0%			
	A	B	C	D	A	B	C	D
Solar PV System Info								
PV System Size (kW DC)	607	214	812	1399	607	214	812	1399
Metering Configuration (BTM/FTM)	FTM	FTM	BTM	BTM	FTM	FTM	BTM	BTM
Total installed Cost ($/W)	2.05	2.37	6.53	2.17	2.05	2.37	6.53	2.17
Solar PV Production								
Year-1 Estimated System Production	701,210.40	275,043.60	1,258,345.00	1,678,481.00	701,210.40	275,043.60	1,258,345.00	1,678,481.00
Analysis horizon (offtake term)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
LIRR	15%	15%	15%	15%	15%	15%	15%	15%
Deltas (Outputs)								
ULIRR	9.21%	9.33%	10.70%	8.93%	4.95%	10.85%	11.17%	10.38%
NPV Margin	13.66%	16.23%	12.05%	8.12%	24.22%	25.78%	15.91%	16.62%
Construction-period equity	9,266.40	7,034.42	447,183.23	222,353.47	461,816.12	205,487.90	1,896,667.38	1,052,640.32
TE (Tax Equity)	546,272.06	235,291.64	2,382,159.52	1,243,207.09	0.00	0.00	0.00	0.00
Debt	819,914.23	370,075.99	2,738,987.76	1,744,780.19	926,569.94	412,990.00	3,796,488.21	2,195,687.86
Total	1,375,452.69	612,402.05	5,568,330.51	3,210,340.75	1,388,386.05	618,477.90	5,693,155.59	3,248,328.18
Debt / capital stack (DSCR)	1.56x	1.55x	2.17x	1.52x	1.83x	1.84x	2.01x	1.69x
Required PPA (Off-take Rate) ($/kWh)	0.15	0.17	0.27	0.19	0.24	0.27	0.42	0.27
Net cash available to SPV	1,008,359.63	482,012.34	8,621,306.38	1,925,809.55	2,160,111.67	987,527.16	14,060,404.75	4,184,561.61
Equity / project-cost ratio	0.01x	0.01x	0.08x	0.07x	0.33x	0.33x	0.33x	0.32x

Table 1. Overall Deltas

The first results Table 1 compiles the Solar PV System Info and Solar PV Production for the four assets in both policy cases. PV System Size is unchanged by design (607/214/812/1,399 kW-DC for Tyrell/Derby/Dominican/Meriden). Metering configuration is fixed (FTM for Tyrell, Derby; BTM for Dominican, Meriden). Total installed cost per watt is also held constant at the values used in underwriting ($2.05/W, $2.37/W, $6.53/W, $2.17/W, respectively). Year-1 production from the design model is held constant as well (701,210 kWh, 275,044 kWh, 1,258,345 kWh, 1,678,481 kWh), with an unchanged degradation assumption applied over the 20-year analysis horizon.

This table is not expected to change with policy; it functions as a comparability anchor. All subsequent shifts in price or capital structure trace back to the loss of the ITC rather than to a change in resource, design, or cost. The production values originate from a validated PV design workflow (HelioScope-class modeling) which is widely used in non-residential PV and has been benchmarked against measured performance. [22] Also, because the inputs are locked, differences in downstream financial metrics cannot be attributed to system size, production, or cost drift; they arise from financing math and the removal of tax-equity cash flows.

C. Required PPA rate (host price of energy)

In all four cases, eliminating the ITC requires a significantly higher release price to maintain the same 15% LIRR ranging from + 42% to + 60%. This is the most direct, host-facing consequence.

The second table 2 binds the capital stack to operating cash flow. It reports the required PPA that solves to 15% LIRR, the unlevered IRR (ULIRR), and the outturn DSCR under each policy case.
To maintain the same 15% LIRR, PPA increases in every project when the ITC is removed. Tyrell rises from $0.15 to $0.24/kWh; Derby from $0.17 to $0.27/kWh; Dominican from $0.27 to $0.42/kWh; Meriden from $0.19 to $0.27/kWh.

Project	Metering	Required PPA (Off-take Rate) ($/kWh)		Delta ($)	Delta (% change)
		PPA @ 40% ITC ($/kWh)	PPA @ 0% ITC ($/kWh)		
A	FTM	0.15	0.24	0.09	61.78%
B	FTM	0.17	0.27	0.10	59.25%
C	BTM	0.27	0.42	0.16	58.59%
D	BTM	0.19	0.27	0.08	43.92%

Table 2. Off-take Rate Delta

The percentage changes span +42% to +60%. Because all other inputs are constant, this is the minimum price uplift required to preserve investor return under standard financing constraints.

DSCR outturns shift with EBITDA and sizing logic. At Tyrell and Derby, DSCR increases from roughly 1.55× to 1.84× as higher PPAs lift cash flow yet debt remains sizing-limited. Meriden moves from 1.52× to 1.69×. Dominican moves from 2.17× to 2.01×, remaining comfortably above typical thresholds. These patterns are consistent with DSCR-driven debt sizing: higher revenue does not automatically translate into proportionally higher debt once lender limits and stresses are applied. ULIRR shifts reflect the interaction of price and production when PPA is allowed to float. Tyrell's ULIRR decreases (9.21% to 4.95%), while Derby, Dominican, and Meriden show modest increases. This is expected in a LIRR-targeted solve; ULIRR here is diagnostic rather than evaluative. For completeness we report it, but we do not treat it as an indicator of host affordability.

D. Equity at COD and loss of tax-equity capital

With the ITC removed, the non-dilutive tax equity proceeds disappear and the equity check in the COD balloons, by a factor of 4–50× depending on project scale and configuration. This is a binding constraint for most public sector sponsors.

Project	Construction-period Equity		Delta Equity ($)	Multiple (x)	Tax-equity cash-in @ 40% ITC ($)	Tax-equity @ 0% ITC ($)
	Equity @ 40% ITC ($)	Equity @ 0% ITC ($)				
A	9,266.40	461,816.12	452,549.72	49.84x	546,272.06	0.00
B	7,034.42	205,487.90	198,453.48	28.21x	235,291.64	0.00
C	447,183.23	1,896,667.38	1,449,484.15	3.24x	2,382,159.52	0.00
D	222,353.47	1,052,640.32	830,286.85	3.73x	1,243,207.09	0.00

Table 3. Construction Period Equity Delta

The Table 3 reports the source-of-funds at COD for each project and policy case: construction-period equity, tax-equity cash-in, and debt. Under 40% ITC, tax equity contributes materially at COD (Tyrell $546k, Derby $235k, Dominican $2.382M, Meriden $1.243M). Under 0% ITC, tax-equity proceeds are, by construction, zero. Equity and debt fill the gap. Totals reconcile closely between the 40% and 0% cases (e.g., Tyrell $1.375M vs. $1.388M), reflecting the same physical asset being financed in two ways.

The equity line is the binding constraint for most public-sector-oriented deals. With tax-equity absent, equity must rise to close sources-to-uses, even when debt edges up. The debt line responds to higher EBITDA under a higher PPA, but is also constrained by DSCR sizing logic.

Result, by project: Tyrell (FTM): Equity increases from $9.3k to $461.8k (=50×). Debt rises from $820k to $927k; tax equity falls from $546k to $0. Derby (FTM): Equity increases from $7.0k to $205.5k (=29×). Debt rises from $370k to $413k; tax equity falls from $235k to $0. Dominican (BTM): Equity increases from $447k to $1.897M (=4.2×). Debt rises from $2.739M to $3.796M; tax equity falls from $2.382M to $0. Meriden (BTM): Equity increases from $222k to $1.053M (=4.7×). Debt rises from $1.745M to $2.196M; tax equity falls from $1.243M to $0.

The equity multiple is most severe at the smaller FTM sites because tax-equity's share of total sources is proportionally larger in those cases; when it vanishes, the sponsor's check must expand dramatically even after modest increases in debt. Across all four projects, the debt increase is insufficient to offset the missing tax-equity dollars.

E. Equity share of capital stack

When ITC proceeds vanish, equity must replace that capital. Equity's share of the stack jumps from 1–8% to 32–33%.

$$Eq\% = \frac{Equity}{Equity+Debt+ITC_{\text{cash}}+Grants} \quad (4)$$

Scenario	Project	Equity ($)	Debt ($)	Tax Equity ($)	Grants ($)	Total Sources ($)
ITC 40%	A	9,266.40	819,914.23	546,272.06	0.00	1,375,452.69
ITC 40%	B	7,034.42	370,075.99	235,291.64	0.00	612,402.05
ITC 40%	C	447,183.23	2,738,987.76	2,382,159.52	0.00	5,568,330.51
ITC 40%	D	222,353.47	1,744,780.19	1,243,207.09	0.00	3,210,340.75
ITC 0%	A	461,816.12	926,569.94	0.00	0.00	1,388,386.05
ITC 0%	B	205,487.90	412,990.00	0.00	0.00	618,477.90
ITC 0%	C	1,896,667.38	3,796,488.21	0.00	0.00	5,693,155.59
ITC 0%	D	1,052,640.32	2,195,687.86	0.00	0.00	3,248,328.18

Table 4. Project, Scenario, Source, Amount

Project	Eq% @ 40% ITC	Eq% @ 0% ITC	Δ (pp)
A	0.67%	33.26%	**+32.59**
B	1.15%	33.22%	**+32.08**
C	8.03%	33.31%	**+25.28**
D	6.93%	32.41%	**+25.48**

Table 5. Equity share of total sources at COD

To normalize the equity story across sizes and configurations, the Table 5 reports Equity share at COD, defined in Formula (4) above. Under 40% ITC, equity shares are small: 0.7% (Tyrell), 1.1% (Derby), 8.0% (Dominican), 6.9% (Meriden). Under 0% ITC, equity shares converge near one-third for all projects: 33.26%, 33.22%, 33.31%, and 32.41%, respectively.

This normalization is useful for two reasons. First, it displays the structural limit in the capital stack once tax equity is unavailable: debt is constrained by coverage, and equity fills the residual at COD. Second, it avoids scaling effects: the same pattern holds from 214 kW-DC to 1.4 MW-DC.

Doing a case-by-case synthesis, Tyrell School (FTM). In the 40% ITC baseline, Tyrell meets its return target at \$0.15/kWh, funded by \$546k of tax equity and \$820k of debt, leaving a minimal sponsor cash requirement (\$9.3k). Eliminating tax equity lifts the required PPA to \$0.24/kWh and pushes the equity check to \$461.8k even after debt increases to \$927k. The equity share moves from 0.7% to 33.3%—a jump that captures the entire loss of non-dilutive tax-equity dollars. DSCR rises to 1.83× due to higher EBITDA, indicating that lenders remain protected despite the change in investor mix.

Derby School (FTM). The same mechanics play out at smaller scale. With the ITC, Derby clears at \$0.17/kWh, with \$235k tax equity and \$370k debt covering almost all uses. Without the ITC, the PPA requirement climbs to \$0.27/kWh, equity rises to \$205.5k, and debt increases to \$413k. The new equity share settles at 33.2%. The outturn DSCR strengthens from 1.55× to 1.84× under the higher tariff while equity replaces tax-equity at COD.

Dominican University (BTM). This larger BTM project exhibits the same directional shifts with different absolute magnitudes. The 40% ITC case solves at \$0.27/kWh, leveraging \$2.382M of tax equity and \$2.739M of debt; the sponsor injects \$447k of equity, for an equity share of 8.0%. Without the ITC, the required PPA is \$0.42/kWh, debt increases to \$3.796M, and the sponsor's equity rises to \$1.897M for a share of 33.3%. DSCR remains healthy (2.01×), confirming that debt sizing is still coverage-limited even at the higher tariff.

Meriden Schools (BTM). Meriden's 40% ITC run solves at \$0.19/kWh with \$1.243M of tax equity and \$1.745M of debt, supported by \$222k of sponsor equity (equity share 6.9%). Removing the ITC shifts the PPA to \$0.27/kWh, raises debt to \$2.196M, and increases the sponsor's equity to \$1.053M (equity share 32.4%). DSCR moves from 1.52× to 1.69×, again reflecting higher EBITDA with limited change in lender advance.

Across configurations and scales, three results recur. First, the required PPA rises between 42% and 60% when the ITC is removed, even though every technical and cost input is identical. Second, the sponsor equity at COD increases substantially because tax-equity proceeds vanish; the resulting equity share of total sources converges near one-third across all four sites. Third, while debt typically rises with higher EBITDA, DSCR constraints limit the increase, leaving the majority of the gap to equity. The ULIRR movement seen in some BTM cases is a predictable output of a LIRR-targeted pricing solve and does not contradict the central affordability result.

All scenarios satisfy Sources = Uses at COD. The only difference between paired runs is the composition of sources; uses remain anchored to the same installed cost and fees. Year-1 production and degradation are taken directly from the design model and applied identically. The project finance metrics reported (IRR variants, DSCR) follow typical definitions in non-residential PV analysis; the fixed 15% LIRR target creates a clean within-project counterfactual.

IV. Discussion

Situating the findings in the broader policy and finance context. In U.S. project finance, tax credits have historically served two functions: (i) they lower the effective capital cost by providing an early-year cash benefit that can be monetized by a tax-equity partner, and (ii) they improve bankability by enhancing early cash flows, thereby supporting debt coverage and reducing sponsor equity requirements. When the ITC is set to zero, both channels close simultaneously. Our four case studies demonstrate the mechanical result: the PPA must rise to preserve investor returns and coverage, and sponsor equity must replace tax-equity at COD.

This interpretation is policy-neutral: the models do not judge whether incentives should or should not exist. They quantify the trade-off that arises when a large up-front credit is present versus absent. In contexts where policy provides base credits and, in some frameworks, elective or "direct" pay for public/non-profit entities, hosts may be able to achieve energy pricing near or below their retail alternatives; where such credits are not available, the price and equity implications we document here are the expected arithmetic outcome of standard financing constraints.

Analyses of commercial and institutional PV routinely find that tax incentives shift projects from marginal to viable by reducing the effective weighted average cost of capital and by enabling a larger share of non-dilutive funding at COD. Prior work examining elimination of the ITC in commercial solar has shown declines in NPV and IRR and extensions of simple payback, consistent with the direction and scale of our results for educational hosts. In our dataset, required PPAs increase 42–60% and equity at COD increases by $0.2–1.45M across projects when the ITC is removed—magnitudes that reconcile with the typical share of tax-equity funding in mid-scale distributed PV.

Our results also align with market practice around debt sizing: lenders anchor on minimum DSCR thresholds and stress-case coverage, which caps debt regardless of higher nominal tariffs. Consequently, debt rises only moderately in the 0% ITC cases, leaving the bulk of the gap to equity. The convergence of equity share to 32–33% at ITC=0% across varied projects reflects this structural limit.

A. Implications for public-sector hosts (K-12 districts and universities)

For public-sector off-takers, three practical implications emerge:

1. Affordability threshold: The PPA is the budget line item that must pass procurement and board review. A 42–60% increase relative to the paired 40% ITC case can push the tariff above a district's acceptable ceiling or above retail parity for BTM sites. Where budgets are tight or tariff caps apply, this can defer or cancel otherwise sound projects.
2. Equity availability and timing: When tax-equity proceeds are not available, sponsor equity substitutes at COD. For public hosts, that equity is often mobilized via third-party ownership structures; higher equity requirements can reduce the pool of willing capital providers or require longer negotiation to balance risk/return, slowing deployment.
3. Metering configuration matters but does not change direction: BTM projects can maintain part of their value proposition by offsetting retail consumption and leveraging bill credit mechanisms, which can moderate the required PPA increase in percentage terms. FTM projects, by contrast, monetize output predominantly through the PPA itself, rendering them more sensitive to incentive removal.

B. Baseline, Practical Risk Implications and Limitations

The baseline for each project is its own 40% ITC case with identical inputs and 15% LIRR. This internal baseline avoids cross-site confounders and allows clean deltas in PPA, equity, and coverage. The interpretation should remain cautious on two fronts. First, the ULIRR movement under a floating PPA is not an evaluative signal of the policy effect; it is a by-product of the pricing solve. Second, higher "cash available to SPV" in some 0% ITC runs reflects the higher PPA, not improved host value; results should be presented with explicit host-side metrics wherever available (e.g., bill savings for BTM, roof-lease revenues for FTM) to avoid misinterpretation.

While this paper does not advocate specific policies, several practical levers can mitigate affordability and equity constraints within prevailing rules:

- Capital stack optimization. Where permissible, layering state or local capital grants, infrastructure funds, or green bonds can reduce required equity at COD and moderate PPAs.
- Cost discipline and scope design. Targeted engineering value-optimization (e.g., module/inverter price negotiation, BOS standardization, O&M service level calibration) can lower CAPEX and OPEX, which our sensitivities show are among the strongest drivers of PPA requirements.
- Contract structuring. Aligning PPA escalators with host budget practices, including modest initial discounts or step structures, can help projects meet near-term affordability tests while maintaining long-term economics for sponsors.
- Schedule and interconnection risk management. Early utility engagement and permitting diligence reduce carrying costs and contingency draws, protecting coverage and equity sizing.
- Revenue complements. Where applicable, renewable energy credit programs or local clean-peak/ancillary value can modestly reduce the PPA required to meet the return target.
- These levers do not overturn the core arithmetic documented here, but they can narrow the gap in specific contexts and help projects clear institutional budget thresholds.

Our sample comprises four projects across two metering configurations. While the projects are real and representative of mid-scale educational PV, generalization to all geographies requires caution. Regional tariff designs, interconnection costs, and program rules differ, as do lenders' sizing criteria. We also do not model storage augmentation, which can introduce new revenue streams and operating constraints. Finally, we maintain a fixed 15% LIRR target for comparability; sponsors with different hurdle rates will see different absolute PPA requirements, though the direction of results will remain the same when the ITC moves from 40% to 0% under standard financing.

When the ITC is reduced from 40% to 0%, educational rooftop PV projects require higher PPAs (by 42–60%) to maintain a constant 15% LIRR, and equity at COD increases sharply as tax-equity proceeds vanish. Debt rises only moderately under DSCR constraints, causing the equity share of sources to normalize near one-third. These outcomes are consistent across FTM and BTM and are robust to reasonable variations in cost, performance, and escalators. The analysis is diagnostic and policy-neutral; it documents the financial trade-offs that public-sector hosts and financing partners should expect when a major up-front incentive is present versus absent.

V. Conclusion

This paper set out a narrow test: hold the technology, production, costs, loan terms, and return target constant, then change a single policy lever—the Investment Tax Credit—from 40% to 0%—and measure what happens to real public-sector rooftop PV deals in Connecticut. Across four executed projects (two front-of-the-meter, two behind-the-meter), the results are consistent and decision-useful. When the ITC is available and monetized, schools can contract for power at materially lower prices and sponsors can close financing with modest equity checks. When the ITC is absent, the same hardware on the same roofs requires higher energy prices and much larger equity contributions to clear the same 15% levered IRR hurdle. Nothing else changed.

Three empirical findings anchor that conclusion. First, the tariff a school must pay—the required PPA to hold investor return—rises by 42–60% when the ITC moves from 40% to 0%. That range holds across configurations and system sizes: from 214 kW-DC to 1.4 MW-DC, from sale-for-resale FTM structures to bill-offset BTM structures. Second, the sponsor's equity at COD increases sharply as non-dilutive tax-equity dollars vanish. In our Connecticut sample, the absolute increase spans roughly \$0.2–1.45 million per project; the multiple is most pronounced at the smaller FTM sites (=30–50×) where tax equity was an outsized share of total sources. Third, while debt typically inches up as PPA-driven EBITDA rises, DSCR constraints prevent debt from filling the hole; as a result, the equity share of total sources converges near 32–33% without the ITC (versus =1–8% with it). Those three signals—price, equity, and coverage—tell a coherent story of affordability and bankability under otherwise identical conditions.

For Connecticut districts, the practical meaning is straightforward. Budgets and procurement policies set ceilings on acceptable electricity prices. A 40–60% jump in the starting PPA moves many projects out of the range that school boards are prepared to approve, even when the technical case is strong and the roofs are ready. The larger equity checks required at COD create a second hurdle. They lengthen negotiations, limit the pool of financing partners willing to bid, and can push scheduled in-service dates into later fiscal years. None of those frictions are about the physics of PV; they follow from how early-year cash flows are shared between lenders, sponsors, and—when the credit exists—tax-equity investors.

Although the four projects analyzed here are all in Connecticut, the mechanics we document are not state-specific. Any setting with similar non-residential PV costs, school procurement constraints, and DSCR-based lending will exhibit the same direction of change when an up-front credit is present versus absent. Magnitudes will vary with retail tariffs, local incentives, interconnection costs, and whether hosts can access additional revenue (for example, state-level credits), but the arithmetic remains: if the return target and debt standards are held constant, removing a large early-year benefit requires higher prices and/or more equity to close the same gap. That is what the data show.

The paper's contribution is not a national forecast; it is a disciplined counterfactual built from real project files with controlled assumptions and clearly auditable outputs. By reporting both host-facing indicators (required PPA) and financing indicators (equity at COD, DSCR behavior, equity share of sources), and by presenting results across both FTM and BTM structures, we provide a template other districts and universities can reuse. Replicability matters. A superintendent in another state can plug in local costs and tariffs, hold the same controls, and see how the PPA and equity terms move as the credit setting changes. That, ultimately, is the value of this work to practitioners.

This analysis is intentionally policy-neutral. It does not argue for or against any statute. It quantifies tradeoffs that school administrators, financing partners, and policymakers routinely face. If the public objective is to expand school-sector solar while maintaining budget predictability, the evidence here indicates that a 40% ITC, once monetized—whether through tax equity, transferability, or other permitted mechanisms—lowers the price schools need to pay and reduces the equity schools' partners need to contribute at COD. Where such an up-front benefit is not available, the same roofs and panels still work technically, but the PPA and equity math looks very different. Recognizing that difference is not a critique; it is a precondition for planning.

The study has limits. Four projects cannot capture every geography, tariff design, or procurement rule. We did not model storage-augmented systems, and we held the return target fixed at 15% to ensure comparability; sponsors with different hurdle rates will solve to different absolute PPAs. Those caveats do not alter the central result: under standard underwriting, the presence or absence of a sizable early-year credit is the dominant driver of the price schools must agree to and the equity their partners must supply.

In short, for Connecticut's public schools—and by extension, for similarly situated districts elsewhere—the 40% ITC functions as an affordability and bankability mechanism. It helps keep PPAs within board-approved ranges and replaces scarce sponsor equity with non-dilutive capital at COD. That is why the four case studies converge on the same outcome. And that is why, if the aim is to support school adoption of solar while protecting classroom budgets, attention to this single lever is warranted alongside the many technical and operational steps districts already manage.

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