

NEW YORK STATE
PUBLIC SERVICE COMMISSION

Case 15-E-0302 – Proceeding on Motion of the Commission to Implement a Large-Scale
Renewable Program and Clean Energy Standard

COMMENTS BY RICHARD ELLENBOGEN ON

**An AI Analysis of the CLCPA that Shows it will raise Utility
rates between 50% and 150% over the Next 40 years with no
rate relief appearing for between 100 – 150 years, IF EVER**

**Prejudices Inherent in the Drafting of The CLCPA Introduced a
Rigid Framework, Unsupported by Scientific Facts, That
Preclude Better Long-Term Solutions from Both a Carbon
Emissions Standpoint and an Economic Frame of Reference**

April 21, 2026

ABOUT THE AUTHOR

Richard Ellenbogen is an active party in the case, a resident of the State of New York, the CEO of Allied Converters, and welcomes the opportunity to provide comments as requested by the Commission in the above referenced proceeding, issued in the May 18, 2023 “Order Initiating Process Regarding Zero Target”.

He is a Former Bell Labs Engineer that worked in the Power Systems Laboratory there. He has done work on the Utility System with NYSERDA and Con Ed. He also decarbonized his factory starting in 1999 and those measurements resulted in the Public Service Commissions Case 08-E-0751 to reduce power line losses. He was an invited speaker to a PSC Utility Conference in 2008 for that case on Line Loss Reduction that was initiated by Steven Keller of DPS based upon the author’s work at the factory and a paper written at the request of Con Ed after a factory visit. He was the Keynote Speaker at the 2023 Business Council of New York State’s Renewable Energy Conference and an invited speaker at the Dutchess County Chamber of Commerce meeting on Energy. He was an early adopter of renewable technologies going back to the 1990's and decarbonized both his home and his business two decades ago. Between 2006 and mid-2023, the business recycled or repurposed 100% of its waste and sent nothing to a landfill. From 2023 until the end of 2025, that figure has been 99% recycling/repurposing.

Over the past 20 years, the factory has generated between 60% and 85% of its electrical energy onsite with a carbon footprint approximately 30% - 40% lower than the Con Ed System, even prior to the closing of Indian Point. The total energy costs at the facility were \$1.19 per square foot in 2024 and 2025 whereas the average energy costs in the Northeast United States for a facility of that type are between \$4.00 and \$7.00 per square foot. Despite energy costs increases in NY State and the Con Ed area during that time, the costs there have been flat due to increased investment in energy recovery infrastructure.

Over the past three years, he has explored adding energy storage to the systems at the factory to offset the likelihood of energy failures in the Con Ed service area that have been documented by the NYISO in the 2025-34 Reliability analysis. He has been expecting that this would be a necessity since the CLCPA was passed in 2019 and has written extensively on the subject so the energy storage project has been on the schedule for over six years. An analysis of the proposed project done by the US DOE has indicated that by storing energy generated overnight by the over 70% efficient generation located on-site at the factory, an additional 24% carbon reduction could be obtained.

Certain parties to these hearings have claimed that every other party asking the PSC to invoke the clause in PSL66-p(4) is supported by the fossil fuel industry or some other nefarious moneyed interest. The author has never taken any funding from any third party of any type and in fact, has spent thousands of dollars of his own money and incurred thousands of hours of opportunity costs over the past seven years in an effort to explain to NY State why their policies will not work. It is entirely based upon engineering, math, economics and physics, not ideology or an effort to enrich himself at the expense of the NY State ratepayer.

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INTRODUCTION

This document presents an analysis using the results of other locations farther along in the process (Germany and Australia) that will show that if the state attempts to implement the CLCPA as written, NY State ratepayers can expect to experience 50% -150 % rate increase through approximately 2060 with no rate relief appearing until 2080 at the earliest, and likely closer to 2100. These cost increases are just those related to CLCPA implementation. With the current state of technology, the population density of NY State, budget limitations, equipment shortages, labor shortages, and the state's climate, it will be virtually impossible to enact the CLCPA as written in any reasonable time frame and those factors will further increase costs. Numerical and historical evidence will be presented, and a Perplexity AI analysis using non-biased queries will confirm the numbers and the facts.¹ All of the AI interrogatories have been included so that doubters can duplicate the results and see the reality for themselves.

As a result, the PSC will have to take actions under PSL 66-p(4). If they choose to postpone the decision and kick the can down the road, it will not change the reality. It will just increase the level of pain when they are forced to do it at a later date after the situation becomes even more dire than now to the detriment of NY State ratepayers. AI interrogatories and responses are presented in italics, including in the appendices. AI responses were fact checked for accuracy for the present day. The author's hope is that confirmation of the sources of NY State's predicament from the world's computer database, based upon unbiased questions, will enlighten people and show that asking the PSC to do what is necessary is not related to money or ideology.

THE NY STATE UTILITY RATE PREDICAMENT

The number of utility customers in arrears started increasing rapidly after 2019. Some of that could be related to the pandemic and some of that could be related to the closure of Indian Point. However, those events were five years ago in 2020 and 2021. At the end of 2023, the state government allocated an extensive amount of money to utility rate relief and arrears are worse now than prior to the passage of the rate relief.

Further, querying AI with the following resulted in an enlightening response. Note that the AI referenced the CLCPA as an issue without any hint of that in the question.

How much did the NY State government allocate to utility rate relief in 2023 and what has happened to utility arrears since?

In 2023, New York State allocated about \$922 million to utility bill relief through the Electric and Gas Bill Relief Program (Phase 1: \$250M from 2022–23 budget for low-income EAP customers; Phase 2: \$672M for non-EAP residential/small commercial, funded by utilities + 0.5% ratepayer surcharge).

1 - The author knew which questions to ask Perplexity.ai because years of reading and nearly 50 years of experience with energy systems has informed his worldview with the first few years spent working on the energy systems for AT&T, which at the time was the world's largest utility. He has spent the past seven years trying to warn NY State about the predicament that it now finds itself in.

Utility arrears since 2023

Arrears have surged despite relief:

- **Early 2023:** ~1.2–1.3M households, \$1.7–1.8B owed (pre-relief peak).
- **End 2024:** 1.38M customers in arrears (>60 days), total accumulated ~\$1.86B (up 32% customers since 2019).
- **End 2025:** 1.3M households, \$1.8B owed (avg \$1,432/customer); ConEd alone \$871M from 414k accounts.

Relief prevented ~478k terminations short-term, but rising rates (CLCPA/grid costs) drove arrears back up—now 1 in 8 households affected, with no sustained drop post-2023 credits.

NY State spent nearly \$1 billion on rate relief 2-1/2 years ago and the situation is as bad or worse now, when compared to before the rate relief. One out of every eight utility customers is in arrears.

As part of the recent Con Ed rate case, hundreds of millions of dollars were allocated to electrification to support the CLCPA. The author sat through that entire rate case for six months and objected to them. Every dollar spent on grid expansion used solely to support building electrification for the CLCPA or Local Law 97 also incurs local taxes that further increase utility rates. If the electrification actually would reduce carbon emissions, then someone could make an argument that it was beneficial. However, powered by the downstate region's aging generation fleet, that is not the case and it will further stress an already compromised system. It is diverting funds from necessary infrastructure upgrades that would actually enhance reliability.

National Grid is spending \$250 million for Synchronous Condensers in the northern part of the state to support grid stability under CLCPA parameters. Those are not needed with large spinning generators but are essential for inverter-based generation associated with renewables. This is one of the "hidden" costs for mandatory equipment in a renewable system that is ignored when people say that "Wind and Solar" are less expensive.

All of these additional ancillary costs trickle down to the ratepayer until they can no longer afford their bill. The reasons for this will be shown later in the document. Disputes have emerged as to what the actual timeline for achieving the aggressive goals of the CLCPA should be.

The analysis will show that arguing about the dates is irrelevant because the required timeframe for full implementation of the CLCPA will be many decades beyond the target dates despite the wishes of the proponents. You cannot wish away Physics. It just does not care.

AN ANALYSIS OF THE CLCPA AND WHY THE CURRENT HIGH COSTS HAVE MANIFESTED THAT NECESSITATE THE PSC INVOKING PSL 66-p(4)

The Climate Action Council (CAC) violated almost all of the rules, the first three listed below, for establishing a successful engineering project. That isn't entirely surprising as most of them were not engineers, their ringleader was a biologist, and rebuilding the entire utility system of NY State is a huge engineering project that needs adherence to details. That attention to detail was sorely lacking.

RULE 1: Establish the Goals and Determine the Available Budget

RULE 2: Research prior projects that may have had commonalities with the effort to determine potential shortcuts and to also avoid pitfalls

RULE 3: Look at all potential solutions without prejudice to determine which one works best from an operational point of view and an economic point of view

Regarding Rule 1, while the goals may have been established, there was never a valid budget established. Seven years later, no one can say what the actual costs are and how they are going to be paid for which is why the PSC is in its current predicament and requested these statements.

Regarding Rule 2, it is blatantly apparent that no one ever checked to see what prior projects might have been done elsewhere because if the CAC had done that, they would have found a major issue that would have made any objective person reflect on the effort. Contrary to NY State's name for the Climate Policy, "Climate Leadership and Community Protection Act", it really isn't leadership. Several jurisdictions had been trying the exact same thing for years prior to NY State's hopping on the bandwagon in 2019 and declaring themselves a "leader".

Germany had commenced *Energiewende* in 2000. The following AI information confirms what the author determined independently in 2019 which will be shown below the search, so AI was not required to make this determination.

An AI interrogatory yielded the following:

What year did Germany commence *Energiewende* and what year did the results start to flatline?

*Germany commenced the **Energiewende** (energy transition) in 2000, marked by the Renewable Energy Sources Act (EEG) that introduced feed-in tariffs and nuclear phase-out agreements under the Red-Green coalition.*

*Results started to **flatline around 2017**, when renewables stalled below 40% of electricity despite massive subsidies (€160B+ spent), emissions reductions slowed, costs exploded, and import dependence grew—exacerbated by nuclear cuts post-Fukushima (2011) and coal reliance.*

What caused the Energiewende to stall after 2017?

*The Energiewende stalled after 2017 mainly because **the easy gains had already been picked off, while the hard parts of the transition were still missing**: grid expansion lagged badly, permitting slowed wind buildout, electricity prices stayed high, carbon policy remained weak, and Germany continued relying heavily on coal and imported energy.*

Main causes

- ***Grid bottlenecks:*** *Germany needed thousands of kilometers of new transmission, but only a small fraction had been built by 2017–2019, so renewable power could not always reach demand centers.*
- ***Permitting and public resistance:*** *Wind projects faced longer approval times, lawsuits, and local opposition, which sharply slowed new installations after the 2017 wind boom.*
- ***High electricity prices and market design:*** *The system relied on subsidies and a market structure that did not fully reward wind and solar once the easiest growth phase ended.*
- ***Weak supporting policy:*** *Germany did not move fast enough on carbon pricing, coal retirement, or transport-sector decarbonization, so emissions reductions plateaued.*

What the flatline looked like

By 2017, Germany's emissions were roughly stuck near 2009 levels, and analysts were already calling the transition stalled. Wind capacity additions also fell sharply after the 2017 peak, which is one reason many observers say the Energiewende lost momentum around that time.

Note that 2017 was two years before the CLCPA was presented and passed and apparently no one on the CAC tried to figure out why Germany was flailing so that the same thing would not happen here. Seven years later, NY State finds itself flailing along with Germany. Note that Germany has a climate similar to NY State and a slightly higher, but comparable population density. In an article from 2018, e360.yale.edu asked:

Carbon Crossroads: Can Germany Revive Its [Stalled Energy Transition](#)?

The article clearly showed what the AI search above revealed. Google existed in 2018. Mr. Ellenbogen used it to find the article in March 2019 when he researched the subject. Also note the comment about “Grid Bottlenecks” or not being able to send the power to where it is needed, when it is needed. Professor Lindsay Anderson and students at the Anderson Lab at Cornell University did a computer analysis² of the CLCPA as it related to NY State's utility system and determined that even if the CLCPA achieved everything on its wish list, there would still be

2 - <https://arxiv.org/abs/2307.15079> **Heterogeneous Vulnerability of Zero-Carbon Power Grids under Climate-Technological Changes**

[M. Vivienne Liu](#), [Vivek Srikrishnan](#), [Kenji Doering](#), [Elnaz Kabir](#), [Scott Steinschneider](#), [C. Lindsay Anderson](#)

hundreds of hours of rolling blackouts in the downstate region due to energy-related Spatiotemporal issues. In layperson English, not being able to deliver power to where it was needed, when it was needed, the definition of a bottleneck. Had the CLCPA been executed as an Engineering Project and not an Ideological one, based upon efforts that were failing in Germany an emphasis would have been placed on Grid Expansion prior to all other goals. It is the lack of adequate transmission capacity in NY State that has resulted in numerous project cancellations due to an inability to send the generated power to where it was needed and the associated high costs. Monetary Resources are finite and efforts need to be logically ordered to reduce cost of execution. Additionally, in the process of doing one of the AI searches, the AI offered the following unsolicited statement to the following question. The prior questions preceding that were related to transformer shortages and labor shortages extending the timeframe by 20 – 40 years and can be found in Appendix D along with the AI responses. As will be shown later in the document, other issues will extend the timeframe even further than the 20 – 40 years. However, the following AI response with the sentence in enlarged bold font shows the disconnect of the CAC from real world restrictions that they should have been aware of if attempting to execute a project of this magnitude.

With the issues above, how many years will it take for NY State to make the transition?

*No, NY State cannot complete a full electrification transition by its official 2040–2050 targets; realistic timelines stretch to 20–40 years (2045–2065) due to transformer shortages (2–4 year lead times), labor gaps (needing 5–10x current HVAC/electrical workforce), and massive scale (\$400–900B total from generation overbuild, storage, rewiring, grid). **Official plans assume perfect supply chains that do not exist.***

No successfully engineered system is designed this way. A classic example of what can go wrong is CHPE that has had numerous delays, issues, and cost overruns and it is a far smaller project than the CLCPA. Originally planned in 2010 and projected to be operational in 2016, it is now scheduled to become operational this year, ten years late and at 250% of the cost in inflation adjusted dollars. That was happening in NY State when these policies were passed and no one on the CAC thought that the same issues affecting CHPE might also affect the CLCPA being implemented at the same time in the same place but on a much large scale?

Six years later the same website, e360.yale.edu, marveled at the wonders of the renewable energy transition in Germany in 2024.³

As Germany Cuts Red Tape, Renewable Installations Boom

But everything was not going as planned as the following AI response makes clear.

3 - <https://e360.yale.edu/digest/germany-wind-solar-permitting-reform>

How much renewable generation in GW did Germany install in 2024, what percentage increase was it, and how much did renewable generation increase in 2025?

Germany installed approximately 19.4 GW of renewable capacity in 2024 (16.2 GW solar + ~3.2 GW wind), representing a ~12% increase over 2023 additions (from ~17 GW total prior year). Renewable generation increased by ~4 TWh in 2025 (to 257 TWh total, flat from 2024's 256.4 TWh despite capacity growth, due to weaker wind output).

2024 Details

Solar: 16 GW added (record), total capacity ~98 GW.

Wind: ~3 GW (onshore/offshore), total ~72 GW.

Share hit 54–59% of electricity mix.

2025 Update

Generation stayed nearly flat at 257 TWh (58.6% share) as wind fell 3.6% despite 11% capacity growth to ~210 GW total. Solar rose 17% to 70 TWh

To put the above numbers into perspective, NY State has installed 6 GW of solar in the past five years. Germany installed 16 GW in one year, 13.3 times as fast. The 3 GW of Wind generation is 33% of NY States total projected Offshore wind. Despite all of that, they got very little additional energy in return.

Adding 11% more capacity does nothing if there is a wind drought, so despite all of the additional capacity, energy generation was up only 0.3% the following year. The public was not getting any return on what was a substantial investment. The lack of labor, equipment, NIMBY opposition, money, and land in NY State will curtail the state's ability to reach those installation rates, and based upon Germany's experience, even if they can be installed, the huge expense will not guarantee a proportional increase in usable energy.

Germany's renewable energy expansion slowed in 2025, with wind, solar and hydro making up 58.8% of the power mix, marginally up from 58.5% a year earlier.⁴

On March 4, 2026, only six weeks ago, Politico reported that the German Energy Minister said that it isn't going to work as planned and that they should relax the targets.

EU should relax net-zero target, German energy minister says

Katherina Reiche says the bloc shouldn't stick to a 'rigid' climate goal because it is killing their economy.⁵

4 - <https://www.facebook.com/ForbesMENA.English/posts/germanys-renewable-energy-expansion-slowed-in-2025-with-wind-solar-and-hydro-mak/1431519295650626/>

5 - <https://www.politico.eu/article/german-energy-minister-katherina-reiche-says-eu-should-relax-net-zero-target/>

Change the names and addresses and it could be the same article written about NY State. Further, German energy costs are 37% higher than the rest of Europe and can be four times higher than French energy costs in the country next door, depending on time of day. France chose to power their country with nuclear. That mirrors NY State's energy costs being higher than those in Pennsylvania. The following AI response makes that clear:

How much more expensive is electricity in NY State relative to Pennsylvania?

Electricity in NY State is ~30–40% more expensive than in Pennsylvania based on recent residential rates. NY averages 26–28¢/kWh, while PA is around 17–20¢/kWh.

Rate comparison

<i>Sector</i>	<i>NY (¢/kWh)</i>	<i>PA (¢/kWh)</i>	<i>% More Expensive (NY)</i>
<i>Residential</i>	26.5–28.4	17.6–20.2	<i>31–40%</i>
<i>Commercial</i>	20.6–25.3	13.2–17.6	<i>40–50%</i>
<i>Monthly Bill (avg usage)</i>	<i>\$151 (571 kWh)</i>	<i>\$165 (817 kWh)</i>	<i>NY pays less total due to lower usage</i>

Why NY pays more per kWh

*NY's rates reflect dense urban loads, CLCPA renewable mandates, aging infrastructure, and delivery charges (60%+ of bills). PA benefits from fracking gas, more hydro/nuclear mix, and lower density. **Both deregulated, but NY's policy costs hit consumers harder.***

Note that Pennsylvania left the RGGI (Regional Greenhouse Gas Initiative) which applies a carbon tax to all greenhouse gas emitters, including electrical generation. This year that is about \$30 per metric ton of CO₂ and it is increasing every year. In NY City, that is adding about one cent to every KWh consumed by a utility customer. EPA Generation Emissions for NY City are 865 pounds of CO₂ per MWh. There are 2200 pounds in a metric ton. Long Island Emissions are substantially higher at about 1100 – 1400 pounds of CO₂ per Mwh.

Regarding Rule 3 of the engineering process listed earlier states that ideas should not be discarded out of prejudice. However, the entire CLCPA is based upon prejudice against all fossil fuels, including natural gas, and also against nuclear generation. The reasons for these prejudices can be traced to one of the primary drivers of the policy, Professor Robert Howarth of Cornell. Professor Howarth is a Biologist and not an Engineer, but he was placed on the CAC by Governor Cuomo. NY State's methane rules that Governor Hochul is now trying to change as part of the budget process are entirely due to him. His theories that fracking was responsible for the rapid rise in atmospheric methane have since been challenged by experimentation⁶ and were challenged at their inception (See Appendix A) but NY State is living with the hangover of him

6 - <https://agupubs.onlinelibrary.wiley.com/doi/epdf/10.1029/2021GB007000>

having been appointed to the CAC. Page 11 of this document appears in Appendic B with the relevant text highlighted. It will be shown later in the document how these prejudices negatively impact the results in terms of reliability and cost.

It can be shown that at this point in time with the current state of technology, retooling existing fossil fuel plants as combined cycle generating plants is the least expensive and fastest way to reduce emissions while also reinforcing system reliability. Several of the author's prior filings explained this but an AI analysis shows the costs of retooling the three Long Island Power plants, East Northport, Port Jefferson, and E F Barrett to greatly improve their reliability and to more than halve their emissions is far less expensive than the state's plan for Offshore Wind and BESS Storage, even if Natural Gas prices Double or Triple. This will be explained fully later in the document. However, the CLCPA precludes that retooling so system reliability is suffering and emissions are much higher than could be achieved. That is especially true in the downstate region, where older plants are burning twice the amount of fuel that they would otherwise need, both driving up costs and emissions. Professor Howarth recently wrote an [anti-nuclear op-ed for the Times-Union](#) that glossed over numerous facts and twisted others and that anti-nuclear bias is also reflected in the CLCPA.

You cannot develop a viable, cost-effective, reliable system if you discard every type of existing firm generation from the energy mix at the outset before any research is even done, but that is what was done here. This was a train wreck waiting to happen and we are now there.

Having seen the nightmare that Germany is living with while having a climate and population density similar to NY State, we can now analyze the potential Gold Standard for all renewable locations, Australia. Results from Australia clearly show the timeframe of NY State's current policies.

THE RENEWABLE TRANSITION IN AUSTRALIA AND WHY THE RESULTS THERE INDICATE AN 80 – 150 YEAR TRANSITION FOR NY STATE WITH SKYROCKETING UTILITY RATES FOR OVER 40 YEARS. NY STATE WILL HAVE 4 TO 10 TIMES THE COST PER MEGAWATT-HOUR (MWh) WHEN COMPARED TO AUSTRALIA

Australia started their transition to renewables in approximately 2005. To understand how perfect a location Australia is for this type of transition does not require a great degree of technical sophistication. Figure 1 is a map of Australia superimposed over a map of the United States with NY State in yellow, all to the same scale. Australia is 54 times the size of NY State, but it only has a population of 27.7 million people. 5400% larger in area with 39% more people. 87% of the 27.7 million live within 30 miles of the coastline. The country is 2485 miles from East to West and about 900 – 1400 miles from North to South. That leaves 13% of the population or 3.6 million people in the country's center that is 2400 miles wide and about 1200 miles North to South. 3.6 million people are less than the entire population of Long Island and

Westchester combined. Figure 2 shows the 20 largest urban areas, all on the coast. Melbourne and Sydney combined, with about 5 million people each, contain close to 40% of Australia's population.

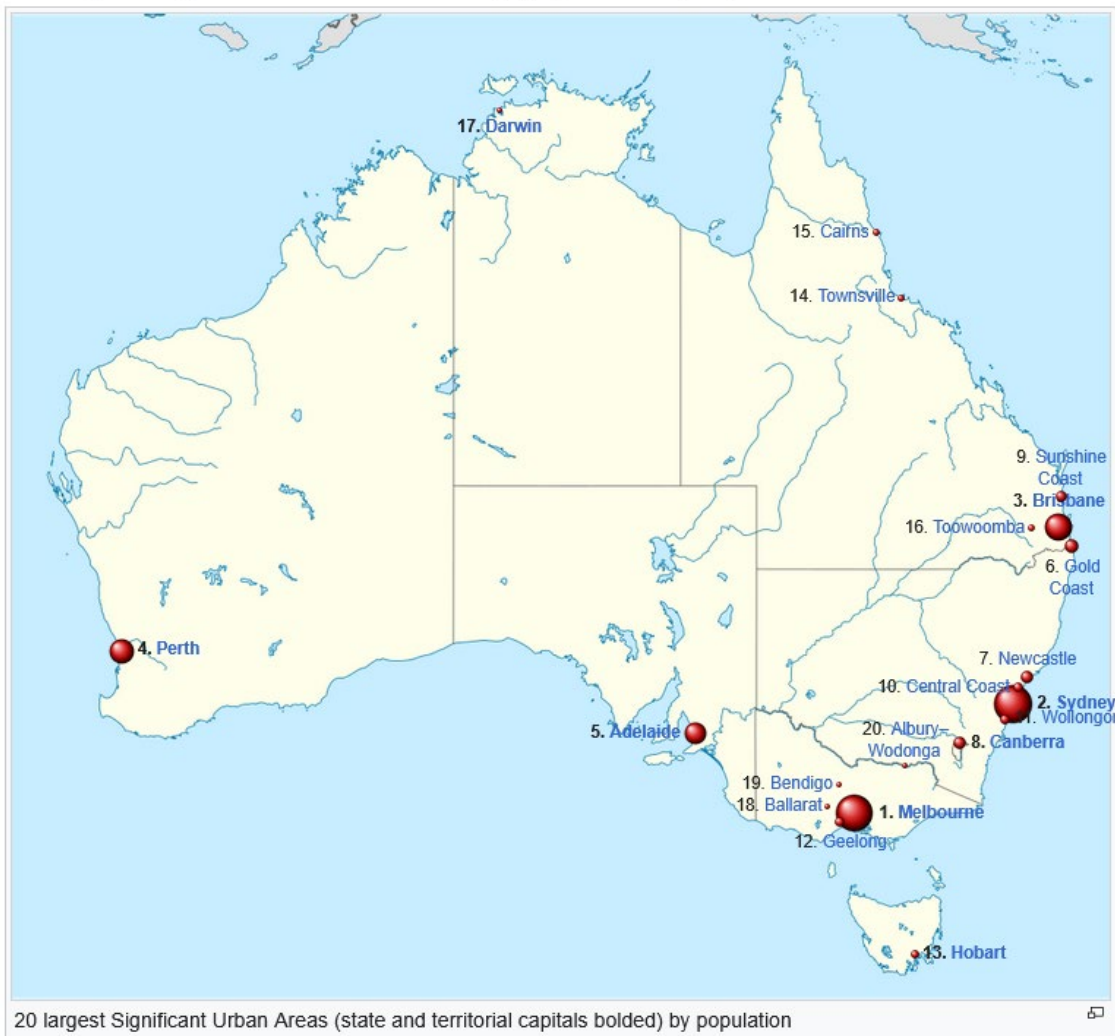
The low population density greatly reduces NIMBY issues, greatly reduces land costs needed to site renewables, and greatly reduces transmission line costs because they can be run overhead and not buried for much of their distance. A 1300 mile long overhead HVDC transmission line will cost the same or less than the 339 mile long CHPE in NY State. Land costs between \$166 - \$2800 per acre in Australia (US Dollars) whereas land in NY State costs between \$5000 - \$8000 per acre. This is a critical factor because the renewable installations require enormous amounts of land. Several solar farms in Australia cover between 5 – 7 Square miles (3200 – 4500 acres). A \$5000 lower cost per acre for land on 4500 acres is a \$22.5 million lower upfront cost for the single array just for the land. Beyond that, NY State's solar capacity factor varies between 13% and 17% whereas the Australian Solar Capacity factor is between 23% and 28%. In Australia, every solar panel will generate nearly twice as much energy which reduces the cost of solar by 50%. Half as many arrays will generate the same amount of energy. Between the savings on land and solar panels, solar energy in Australia is much less expensive.

Figure 1: Map of Australia (Green) superimposed over a map of the United States with NY State in Yellow. Both maps are the identical scale.



Figure 2: Map of the 20 Largest urban areas by population

Map of the 20 largest Significant Urban Areas by population [edit]



The inland area of Australia is ideal for solar with minimal rainfall and very predictable output. But the biggest advantage Australia has when compared to NY is the climate. The annual per capita heating load is about 1000 KWh per person or 27.7 million x 1000 KWH = 27.7 billion Kilowatt Hours (KWh). The per capita heating load in NY State is 5000 KWh per person x 20 million = 100 billion KWh so NY State will need almost four times as much energy for space heating. NYSERDA's 6 GW Energy Storage report stated that 1000+ hours of storage would be needed because of the large winter heating load and minimized renewable output during the winter.

Australia does not have that problem. Their solar arrays operate more evenly throughout the year with less winter drop off except in the far south as the table of seasonal Solar Array output in Figure 3 with output peaking during cooling season. Melbourne is farthest from the equator on the southern coast so the seasonal disparity will be greatest there. Where an array in NY might only make 11% of its energy during the three winter months, the average is closer to 16% - 18% across

Australia with no extended outages due to snow cover. Toward the north in Darwin, the output is level throughout the year. Toward the south, it falls off more in the winter but still higher than in New York because of the lack of snow covering the panels. Many of their arrays are in the large empty center.

Australia has six times as much solar capacity installed as NY. In 2024, wind, solar and hydropower accounted for 96,000 GWh in Australia, only 17% hydro. In NY according to the 2025 NYISO Gold Book, in 2024 they accounted for about 42,500 GWh, 44% of Australia’s total, with 66% of New York’s total from hydro plants that primarily date to the 1960’s so NY State has a long way to go, especially with local resistance increasing upstate. Over 90% of the solar generation in NY State is Behind the Meter. Australia generates 5.5 times as much solar and wind energy as NY State. (80,000 GWh in Australia versus 14,586 GWh in NY State). Depending on the reference document, Australia plans to install an additional 10 - 37 GW of rooftop (BTM) solar by 2030 (equivalent of 20 - 74 GW in NY) or 3 - 12 times what has been installed in NY over the past six years. The NYISO is projecting BTM solar output to increase by only 2.4 times by 2055 and numerous solar projects are being canceled because of cost, so the gap is widening. The low costs in Australia are facilitating the transition. See appendix G for the breakdown.

Figure 3: Australian Solar Array Output by Season in various Cities

City	Summer	Autumn	Winter	Spring
Adelaide	37.8%	20.2%	13.0%	29.1%
Brisbane	30.8%	21.9%	18.2%	29.1%
Canberra	35.8%	20.6%	14.0%	29.6%
Darwin	22.7%	24.9%	24.7%	27.7%
Hobart	40.3%	18.0%	10.9%	30.7%
Melbourne	38.7%	19.6%	12.5%	29.2%
Perth	36.8%	20.5%	14.0%	28.7%
Sydney	33.7%	20.8%	15.9%	29.6%

UTILITY RATES IN AUSTRALIA ONLY STARTED DECREASING IN 2024 -2025

When did Australia's electric rates start to drop due to their renewable transition?

Australia’s electric rates began to show clear downward pressure from the renewables transition roughly from 2022 onward, with the most visible wholesale-price drops arriving in 2024–2025.

When prices started falling

- *Data on 2024–2025 show wholesale electricity prices in key states (New South Wales, Queensland, Victoria, South Australia) dropped by about 10–15% year-on-year, reaching the lowest levels in several years by 2025.*
- *This followed a surge in wind, solar, and battery capacity, which increased supply and drove down short-term prices, including episodes of negative prices when wind and solar output were very high.*

Retail bills vs wholesale prices

- *While wholesale prices fell noticeably starting in 2024–2025, retail bills have not yet fully reflected that drop because network costs, charges, and contracted retail margins lag behind the wholesale market.*
- *Australian-energy-market forecasts now expect residential electricity prices per unit to fall by about 5% over the next five years (through 2030), with the main driver cited as more renewable generation and batteries.*

So, in short: Australia’s wholesale power prices started falling visibly due to renewables around 2024–2025, but the full retail-bill impact is only just beginning to appear.

Despite all of the structural advantages baked into Australia’s location, utility rates only started decreasing last year (2025) after 20 years of policy implementation and they are only expected to decrease by 5% over the next five years.

That does not bode well for NY state. The following question and answer from AI should make everyone seriously reconsider their commitment to the CLCPA.

If it has taken Australia 20 years to reach a point where utility rates are just starting to drop because of the renewable transition, how long will it take NY State to do it with four times the thermal load, 2% of the land for renewable installations, and 40% of the solar capacity factor and how much more expensive will it be?

NY State would likely take 80–150 years to see utility rates drop from its renewable transition, compared to Australia's ~20 years. Costs could end up 4–10x higher per MWh long-term.

Timeline scaling factors

- *Australia's path: Vast land (7.7M km²), high solar factor (~22%), minimal thermal electrification—reached wholesale price drops by 2026 after daytime solar overbuild.*
- *NY's constraints:*

- **4x thermal load:** Winter heating peaks double/triple electric demand (vs. Australia's milder climate).
- **2% land availability:** Forces expensive offshore wind (2–4x onshore costs) and rooftop/distributed solar.
- **40% solar factor** (~12% NY vs. ~25–30% Australia): Requires 2.5x more panels for equivalent output.

These amplify overbuild (4–6x capacity), storage cycling, and grid costs exponentially.

Cost multiplier

Factor	Australia	NY Impact
Land	Abundant	Offshore wind @ \$3–5M/MW (vs. \$1M onshore)
Solar	25% factor	2.5x panels needed @ \$1M/MW
Thermal	Low	Storage doubles for winter peaks

Net LCOE \$50–80/MWh \$200–500/MWh *firmed system*

NY's urban density + policy delays (transformers, labor) push breakeven beyond 2100, with rates likely rising 100–200% first.

Appendix D has a series of questions asked of AI that document the transformer and labor issues mentioned in the response above.

Of great concern to the NY State hearing is the utility rate increases that will accompany the extensive delays in implementing the policy exemplified by the following question:

How much will rates rise before that 60 - 100 year timeframe?

NY residential electricity rates could rise 50–150% over the next 20–30 years (to 40–65¢/kWh by 2045–2050) before any potential stabilization or drop in the 2085+ timeframe, driven by CLCPA-mandated renewables, grid upgrades, and thermal electrification costs outpacing savings. Upstate households face the steepest hikes, with \$2,000–\$4,000 annual bill increases possible by 2030–2035 under full implementation.

Near-term trajectory (2026–2040)

- **2025–2027:** Already underway—NYSEG +9.9% (\$11/mo), National Grid +28% over 3 years (\$14–25/mo), RG&E +26%. Statewide average hit 27¢/kWh in 2025, 50% above U.S. average.
- **2030:** NYSEERDA models warn of \$2,300–\$4,000/yr extra for households under cap-and-invest to hit targets, or 40–60% bill spikes from delivery charges alone.

- *2040: Cumulative 100–150% rate hikes as thermal loads double demand, transformers/labor shortages add premiums, and storage replacements cycle in.*

Long-term before breakeven

*Rates peak mid-transition (2040–2060) at 2–4x current levels due to overbuild (3–5x capacity), storage churn (every 12–15 years), and land limits forcing pricey offshore wind. **Only after 60–100 years might wholesale drops emerge, but retail lags indefinitely amid endless retrofits.***

Household impact

Period Avg. Monthly Bill Rise Annual Extra (600 kWh/mo)

2026–2030 +20–50% \$300–\$1,200

2030–2040 +50–100% \$1,200–\$3,000

2040–2060 +100–150% \$2,500–\$5,000

These hikes compound inflation (experts predict 18%+ through 2030), hitting upstate/NYC renters hardest before any Australia-style relief materializes decades later.

Based upon the analysis. retail utility rates will likely not drop as a result of this policy for at least a century. NY State IS NOT Australia.

THE ISSUES CAUSED BY PREMATURE ELECTRIFICATION PROBLEMS IN AUSTRALIA THAT WILL BE DUPLICATED IN NY STATE

Even with Australia’s superior renewable conditions, it is not immune from Physics as the following will show. “Putting the Cart Before the Horse” or “Electrifying Before Adding Enough Generation and Transmission.”

As per the description in Wikipedia, “Victoria, commonly abbreviated as Vic,^[9] is a [state](#) in southeastern [Australia](#). It is the second-smallest state (after [Tasmania](#)), with a land area of 227,444 square kilometers (87,817 sq mi); the second-most-populous state (after [New South Wales](#)), with a population of over 7 million;^[10] and the most densely populated state in Australia (31.1 per km²).^[11] Victoria's economy is the [second-largest among Australian states](#) and is highly diversified, with service sectors predominating.”

Although it is Australia’s second smallest state, it is still almost two times larger than NY State’s 47,123 square miles. Almost 5 million of the 7 million people live in the Melbourne Metropolitan area. They have passed [gas bans](#) and building electrification mandates and now they are having grid voltage issues with voltages low enough that they [can no longer operate their appliances](#), including their heat pumps. When loads grow faster than generation, system voltage will drop, similar to a “Brownout” on a hot summer day. These are the exact same policies that NY State and NY City are implementing, and they will cause similar issues here. They already are in the Albany

area with over electrification affecting certain areas resulting in “Blue Sky” blackouts because the loads exceed substation capabilities. In Australia, those technologies are operating on a 50% renewable but inadequate system so they will see a reduction in GHG emissions. In New York, the additional electrification will be operating from a far less renewable system, especially downstate so the emission benefits will not be realized. The author has seen the load that his 22 year old electrified home (Geothermal Heat, EV Charger, Solar Array) has been placing on the Con Ed system and has been warning the state for years what an extrapolation of that across the system would do. The Australians are learning about that the hard way.

THE POTENTIAL EFFECT OF NATURAL GAS COSTS ON NY STATE GENERATION

In several prior PSC filings under case 15-E-0302, the author proposed retooling the natural gas plants on Long Island to be the newer type combined cycle plants. It was shown in those filings that greatly reduced emissions could be achieved more quickly than with the policies embedded in the CLCPA. The prior analysis confirmed that fact.

When the previous numbers were presented to a knowledgeable person, the question was asked, “What will reliance on fossil fuels do to costs based upon the current instability in the Middle East?” That question was posed to AI as the following three interrogatories. LCOE is the Levelized Cost of Electricity and it is used to compare the time average cost of a particular generating source including the cost of installation and operation.

What is the LCOE of offshore wind in NY State versus retooled combined cycle natural gas plants on Long Island at Northport, E F Barret and Port Jefferson at 10 years, 20 years, 30 years, and 40 years with natural gas at current cost, and 2, 3, and 4 times current costs

Modify the LCOE calculation to figure in the cost of battery storage needed to make the wind generation dispatchable to the same capacity as the retooled gas plants. Provide values with and without the carbon tax.

Add a 40-year LCOE view for Northport across all three BESS durations — the Year 20–40 carbon tax escalation path most changes whether 6hr or 8hr BESS ever achieves crossover

The response came back with text that is documented in Appendix C and an extensive Excel Spreadsheet that was attached with this filing for use by anyone who wants to review it. The title of the file is “LI Gas vs Offshore Wind LCOE-3”. The spreadsheet will be discussed in a later section. Graphs from the spreadsheets appear in Figure 4 and Figure 5.. Note that the author did not choose the size of the BESS Storage. That was done by the AI algorithm based upon data it found on NYISO specifications for the utility system needed to maintain reliability.

Six different options are shown with four different costs for natural gas. Those costs are the current Henry Hub cost (explained later) and two, three, and four times that cost to account for inflationary factors that might impact fuel costs. Figure 4 shows the 20 year LCOE and Figure 5 shows the 40 year LCOE. At the 20 year timeframe in every scenario, the retooled gas plants were less expensive over a twenty year period than the Offshore Wind plus BESS storage. In the forty year time frame, the LCOE of the gas generation is more greatly impacted by the carbon tax. Also note that the renewable cost does not include the cost of synchronous condensers that would also need to be

installed to maintain system stability in a heavily inverter based system. That would drive the cost of the Wind/BESS System even higher relative to the combined cycle plants.

The state’s carbon tax is a political construct that will artificially drive up prices. It is not a structural construct that aids in recouping costs of providing the commodity and if it is removed, the difference in costs becomes more dramatic. What the spreadsheet also showed is that the carbon tax will raise the price of the generation from the retooled plants by \$14 per MWh but even with that, it would still be much less expensive than the offshore wind. \$14/MWh translates to 1.4 cents per Kilowatt-Hour (KWh) on a utility bill and it is buried in the supply cost. If a customer uses 1000 KWh in a month, that would translate to fourteen dollars paid for the carbon tax for energy from those generators.

What the AI Analysis and the graphs also clearly show is that renewables are less expensive until you have to add the equipment that is necessary to integrate them into the utility system to make them function properly and safely. That is what makes rooftop solar cost effective as it needs minimal other resources to interconnect it to the system. However, that renders remote renewable generation more expensive and has resulted in the cancellation of so many renewable projects.

In NY State, the “Renewable is Cheaper” mantra breaks down quickly. On-shore wind in Texas and solar in Australia are less expensive even with the additional equipment because their capacity factors are so much higher. On-Shore wind in Texas costs \$25/MWh and that is why it has penetrated the market there and now provides over 25% of Texas Energy. The Offshore Wind bids in NY State were priced at \$150/MWh, six times as much. If you redrew Figures 4 and 5 to reflect the LCOE’s of Texas Wind versus Combined Cycle generation, the graphs would look very different with wind having lower costs, but we are in NY State and not Texas.

Figure 4 Relative LCOE’s over a 20 year time frame for four different Natural Gas Price Points – Gas Generation costs shown with and without the carbon tax

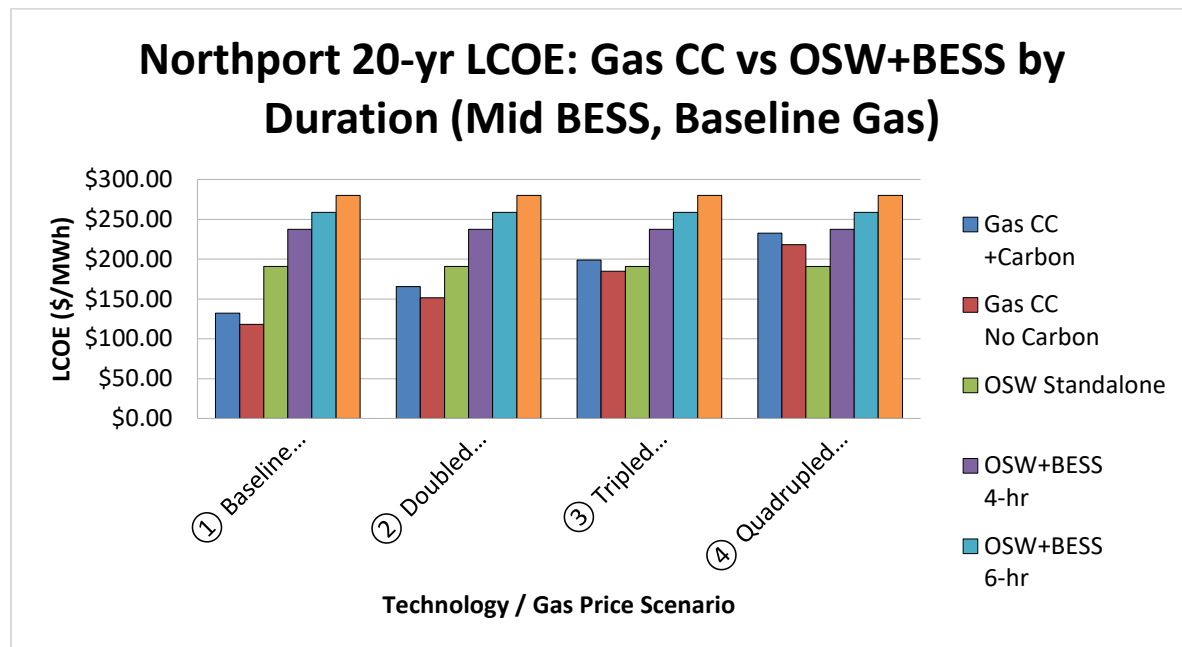
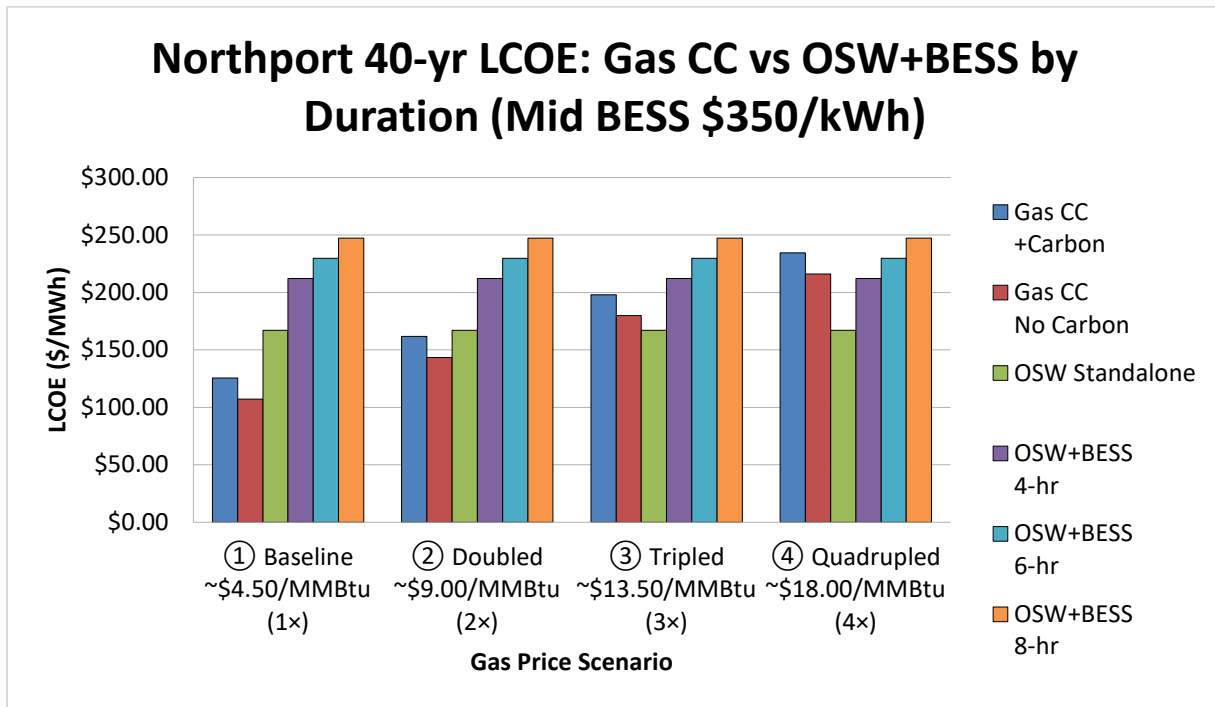


Figure 5 – Relative LCOE’s over a 40 year time frame for four different Natural Gas Price Points – Gas Generation costs shown with and without the carbon tax



Additionally, it is very unlikely that gas prices will triple or quadruple because economic forces at the \$9.00 per MMBtu level are so much higher than what the drillers need to be profitable that they will greatly expand drilling capacity which will at a minimum, moderate costs if not cause them to drop.

The Marcellus Shale is in Pennsylvania and the Bakkan Shale is in North Dakota. The Bakkan Shale produces primarily oil and natural gas is only a byproduct. The following question was asked of AI:

At what price point does Marcellus and Bakken Shale Gas Drilling increase historically?

The full response is extremely long and is presented in full in Appendix E for those that want to read it, however the relevant text from the answer is below in italics. It is based upon the fact that the drillers in Pennsylvania break even at \$2.00 per MMBtu and at the current costs of \$4.50, they are highly profitable. At \$9.00/MMBtu, they would be in a rapid expansion mode. The only issue would be if the gas supply was constrained by inadequate pipeline capacity, however retooling the three Long Island plants would cut their gas use by 40% and their emissions by far more than that. The reduced gas use would free up capacity and cause downward price pressure. “HH” is an abbreviation for Henry Hub which is a major physical pipeline interchange located in Erath, Louisiana, that serves as the official delivery location and benchmark price for US natural gas futures contracts traded on the CME/NYMEX. Historical Henry Hub pricing can be [found here](#).

*The current LI delivered gas price assumption is \$4.50/MMBtu (HH \$3.52 + \$0.98 Zone 6 basis). At that level, Marcellus is solidly in growth-drilling mode — the \$3.00 inflection has already been crossed. For supply-side price response to be a binding constraint on your 2× and 3× gas scenarios (\$9.00 and \$13.50 LI delivered), you'd need HH to reach roughly \$8–\$12.50/MMBtu. At those levels, the Marcellus would be drilling at full capacity, but **takeaway constraints** (pipeline into Zone 6/New England) would likely cap incremental supply into the NY/LI market even if wellhead production surged — meaning basis differentials could widen substantially, partially muting the HH signal at the wellhead.*

The information above shows a reduced cost, lower carbon interim option for the state's utility system. It will not be of an indeterminate length because the gas supplies are finite. However, if NY State is looking to address its rapidly rising utility rates, this clearly shows the most cost-effective path forward, regardless of Federal Government policy.

WHAT IS THE BEST LONG-TERM OPTION FOR GENERATION IN NY STATE?

What is the lowest cost, long term, carbon free generation option? When AI was asked to compare Renewables and Nuclear to determine the lowest cost option, it returned the following:

***Nuclear alone cannot meet NY's Climate Plan targets** because the state's Climate Leadership and Community Protection Act (CLCPA) legally mandates **70% renewable electricity by 2030** and **9 GW offshore wind specifically**—solar and wind are required by statute, not optional, even if nuclear provides dispatchable backbone.*

As clearly shown by the response, the statute is determining the system as opposed to price or a quantitative analysis of the various technologies. That is a clear example of the prejudice built into the CLCPA policy that is negatively impacting reliability and driving up customer rates. The source of the prejudice inherent in the CLCPA is documented in Appendix F. When the time frame and all restrictions were removed to eliminate prejudice, the response was quite different. The summary of the results is in the following sentence with the AI response below it.

A Nuclear heavy system would be between 20% and 50% of the cost of a renewable system and the nuclear system would have a higher reliability as the following response clearly shows.

Removing the CLCPA's timeframe, which would be the better and cheaper system over a 60 year period?

Over a 60-year horizon without CLCPA's tight deadlines, a nuclear-heavy system would be cheaper and more reliable than one dominated by solar, wind, overbuild, and storage. Nuclear's

60–100 year lifespan, 90%+ capacity factor, and minimal system costs (no backups needed) yield lower lifetime LCOE (~\$80–130/MWh) versus firm renewables (~\$100–250/MWh including replacements every 20–30 years).

Cost comparison

System	Capex (first 20 yrs)	60-yr LCOE	Replacements	Land/Transmission
Nuclear	\$6–10B/GW	\$80–130/MWh	Minimal (refueling)	Low
Solar/Wind + Storage	\$2–4B/GW (nameplate)	\$100–250/MWh	Every 20–30 yrs (\$trillions)	Massive

Nuclear wins long-term: no degradation, no curtailment, full dispatchability. Renewables require 2–4x overbuild + storage cycling losses, driving higher system costs despite cheap upfront panels.

Reliability edge

Nuclear provides firm power 24/7/365 without weather dependence or multi-week lulls. A renewables-heavy grid needs backups (gas or endless storage), adding 20–50% to costs; nuclear grids (e.g., France) achieve 70–90% clean power stably.

Optimal mix

80% nuclear + 20% renewables/hydro minimizes costs at ~\$90/MWh over 60 years—leveraging nuclear baseload with cheap solar/wind peaks. **Pure renewables fail economically past 50–60% penetration without heroic overbuild.**

Additionally, in a nuclear dominated generation system, excess electricity or heat from the nuclear plants could be used to generate hydrogen that could then be used in the pre-existing gas plants to provide peak response with greatly minimized emissions. It would also use pre-existing infrastructure to reduce costs.

CONCLUSIONS

All of the interrogatories presented to Perplexity AI in the document were asked without adding biases to try to elicit a particular response. The author's intent was to demonstrate the magnitude of the problems facing NY State with its current policies and to show the most reliable, reduced carbon or carbon free path, and the least expensive path forward because utility rates do matter. In NY State those have become untenable to the point that residents can no longer afford to live here.

The author hopes that others will duplicate the questions on their own so that they can see the reality for themselves. This is not ideological or driven by monetary pursuit.

Further, the AI systems are not ideological, and the AI algorithms search across all databases to generate the best answer. The AI analysis and the resulting numbers show the following:

- The CLCPA will not achieve its climate targets for many decades and possibly for a century. That is far slower than other paths forward.
- The CLCPA has Prejudices built into it that prevent execution of the most effective and economic solutions and it is already resulting in rapidly rising utility rates.
- Utility rates under CLCPA policies will rise 50% - 150% over the next 30 – 40 years and retail rates will likely never be reduced by the policy.
- Retooling Long Island's natural gas plants is less expensive than Offshore Wind and battery storage as a short term (40 - 60 year) solution. It will also reduce emissions by over 40%.
- Nuclear generation is the least expensive long term path forward for NY State with a much higher reliability and costs that are 20% to 50% lower than renewables. Waste heat and excess electricity from the nuclear generation could be used to make hydrogen that could be burned in the pre-existing gas plants to offset peaking loads with minimal emissions.

NY State has been led astray by people that put ideology over science and engineering. Physics is an unrelenting force and those that believe that they can ignore it will have to deal with the consequences. Unfortunately, some of those people were put in charge of the CAC and wrote the CLCPA, and we are currently living with the consequences of their actions.

To minimize the damage caused by the CAC and stabilize NY State's utility system, the Public Service Commission will have to invoke the relevant terms in PSL-66p(4).

APPENDIX A

What specific flaws were identified in Howarth's 2011 shale gas study?

Yes, Bob Howarth's 2011 study "Methane and the greenhouse-gas footprint of natural gas from shale formations" faced significant criticism for methodological flaws shortly after publication. Key issues identified by multiple expert reviews (DOE/NETL, Cornell peers, IHS-CERA, Wood Mackenzie) include:

Major flaws cited

- ***Grossly overestimated flowback emissions:*** Assumed 100% methane venting during well completion/flowback, when 62%+ is actually flared or used on-site for equipment power (DOE 2011). Estimated vented volumes exceeded well IP rates, physically impossible.
- ***Extrapolated from limited/unrepresentative data:*** Used small sample of high-emission early wells (pre-regulation), ignored modern green completions and low-leakage operators.
- ***Misinterpreted "lost and unaccounted for" gas:*** Treated as vented methane rather than measurement error/meter bypass.
- ***No sensitivity analysis or contemporary practices:*** Ignored rapid adoption of controls (flaring, reduced emissions completions) post-2010.
- ***Flawed functional unit:*** LCA compared shale gas to coal without accounting for gas's superior efficiency in power plants (50–60% vs. coal's 33–40%).

Impact

These errors inflated leakage rates 4–6x (6% vs. EPA's 1.4–2.3%), making shale gas appear worse than coal on 20-year GWP. Corrected analyses showed 20–50% lower climate impact than coal. Study retracted/revised elements but core claims remain debated.

Follow-ups

What did Lawrence Cathles say about Howarth's methane estimates

How did NETL study refute Howarth's flowback emissions

What were IHS-CERA's main criticisms of the 2011 study

Did Howarth respond to these methodological critiques

How do actual shale gas emissions compare to Howarth's claims

What did Lawrence Cathles say about Howarth's methane estimates

Lawrence Cathles, a Cornell geophysicist, sharply criticized Howarth's 2011 shale gas methane estimates as "unreasonably large and misleading" in his 2012 rebuttal paper. He argued the leakage rates (3.6–7.9%) were inflated 4–6x beyond credible data, making natural gas appear worse than coal over 20 years.

Cathles' key points

- ***Impossible flowback volumes:*** *Howarth assumed massive venting during well completions that exceeded initial production rates—physically implausible without frequent fires (which don't occur).*
- ***Cherry-picked data:*** *Combined U.S. shale outliers with Russian pipeline leaks, ignoring modern flaring/reduced-emission completions adopted post-2009.*
- ***Wrong functional unit:*** *Failed to compare gas power plants (50–60% efficient) vs. coal (33–40%), overstating climate impact. Even at Howarth's leak rates, gas was still cleaner.*
- ***No systematic averaging:*** *Extrapolated extremes without industry-wide data or sensitivity analysis.*

Outcome

*Cathles concluded methane leakage was a "red herring"—gas remained a viable bridge fuel. Howarth rebutted, citing newer EPA estimates, but Cathles' critique aligned with DOE/NOAA findings showing 1–2% leakage. **Debate continues, but Howarth's numbers widely seen as upper-bound outliers.***

APPENDIX B

Page 11 of Global Biogeochemical Cycles

Improved Constraints on Global Methane Emissions and Sinks Using $\delta^{13}\text{C}$ -CH₄

X. Lan^{1,2} , S. Basu^{3,4} , S. Schwietzke^{1,5} , L. M. P. Bruhwiler² , E. J. Dlugokencky² , S. E. Michel⁶ , O. A. Sherwood^{6,7} , P. P. Tans² , K. Thoning² , G. Etiope^{8,9} , Q. Zhuang¹⁰ , L. Liu¹⁰ , Y. Oh^{2,10} , J. B. Miller² , G. Pétron^{1,2} , B. H. Vaughn⁶ , and M. Crippa¹¹

FULL DOCUMENT AVAILABLE AT THE FOLLOWING LINK

<https://agupubs.onlinelibrary.wiley.com/doi/epdf/10.1029/2021GB007000>

RELEVANT INFORMATION FROM THE DOCUMENT SHOWN ON THE FOLLOWING PAGE AND IN HIGHLIGHTED TEXT.

This paper documented experimentation based upon taking methane samples out of the atmosphere and analyzing the carbon isotopes present in the methane to determine the source.

The predominant form of carbon isotope found in the samples was from microbial decay of organic matter and not from fossil fuels. Thus, the highlighted caption on the following page copied from the paper at the link above.

While methane emissions from fossil fuel extraction did increase, it was far less than the numbers used by Howarth and more in line with the calculations and statements of Cathles shown in Appendix A.

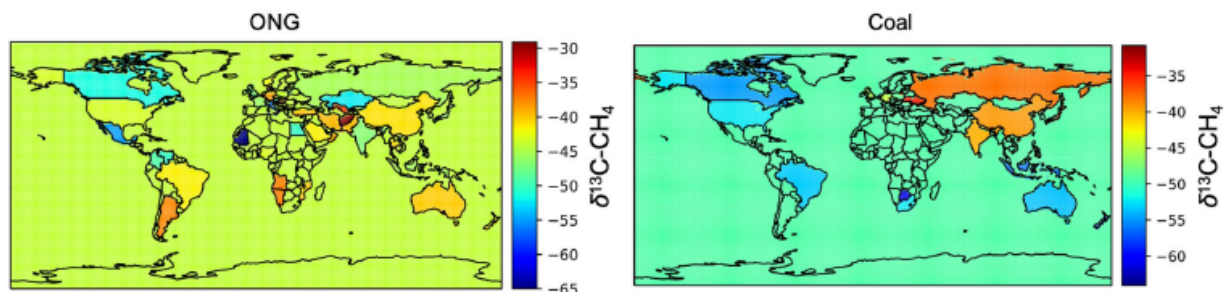


Figure 3. Country-level $\delta^{13}\text{C-CH}_4$ source signatures for ONG (2010) and coal emissions (assume time invariant). For grid cells without data, a global flux weighted mean is used. ONG, Oil and Natural Gas.

3. Results

3.1. Updated $\delta^{13}\text{C-CH}_4$ Source Signatures

Compared with the v2017 of the source signature data set (Sherwood et al., 2017), the sample size for FF $\delta^{13}\text{C-CH}_4$ signatures in v2020 is 8% larger (new total sample count is 9,477). The updated v2020 of $\delta^{13}\text{C}_{\text{FF}}$ samples is representative of FF emissions from 47 countries accounting for $\sim 81\%$ of global ONG and $\sim 90\%$ of global coal production. Figure 3 shows maps of ONG and coal $\delta^{13}\text{C-CH}_4$ signatures. The inclusion of additional data has negligible effect on global mean FF signature, but there are regional differences in $\delta^{13}\text{C}_{\text{FF}}$ signatures when comparing with v2017. By accounting for the rapid development of shale gas production in the U.S. and the shifting ONG production across different basins, we find that the U.S. shale gas signatures have become heavier than conventional gas signatures (Figure S3; Milkov et al., 2020). This is in disagreement with Howarth (2019) who used a more depleted $\delta^{13}\text{C-CH}_4$ signature for shale gas to support the hypothesis that the increase in U.S. FF emissions is the dominant contributor to the post-2006 global CH_4 increase. Given the shift toward more shale gas production relative to conventional gas, the U.S. ONG signature (as a production-weighted mean of shale and conventional gas production) increased by 2.7‰ from 2006 to 2016.

For the Mic and BB signatures, the source signature database update results in a 74% increase of Mic samples (new total sample count is 1,776) and 3% increase of BB data (new total sample count is 935). The new gridded data with a larger sample size constitute a stronger constraint to attribute emissions to specific regions and individual source categories in modeling.

When we apply the default sink scenario and sink fractionation ($\epsilon = -7.85\%$, in Equation 4) from TM5 (see default sink description in Section 2.5) in the mass balance equations, we estimate that 167 Tg/year FE (assuming no temporal trend) and 360–420 Tg/year Mic emissions (from 2000 to 2016) best matches the top-down emission constraint combined with global mean signatures that are calculated by weighting grid-level signatures and emissions. If we use $\epsilon = -6.3\%$ as the total sink fractionation factor, the same as in Schwietzke et al. (2016), the FE constrained by the new grid-level signature and emission is 210 Tg/year which is comparable with the 195 ± 32 Tg/year estimates for 2003–2013 from Schwietzke et al. (2016). This FE magnitude also in good agreement with the annual FE estimate of 168 ± 13 Tg/year for 1984–2000 based on radiocarbon ($^{14}\text{CH}_4$) measurements, when using $-6\% \pm 2\%$ as the total sink fractionation factor in their study (Lassey et al., 2007). A recent study (Fujita et al., 2020) found that the optimized emissions from CH_4 inversion still underestimate FE and overestimate Mic emissions. FE was adjusted to 162 ± 2 Tg/year to best fit both $\delta^{13}\text{C-CH}_4$ and $\delta\text{D-CH}_4$ observations at Arctic and Antarctic surface stations.

3.2. Simulated Global Mean CH_4 and Its Latitude Gradient

Emission scenarios described in Section 2.4 are simulated in the TM5 transport model to produce 4D fields of atmospheric CH_4 and $\delta^{13}\text{C-CH}_4$. Simulated global mean CH_4 of all scenarios compares reasonably well with observations (Figure 4a), which is expected since all scenarios were constructed to have global total emissions consistent with the atmospheric CH_4 global mean growth rate. However, the agreements with the

APPENDIX C

GAS PLANT LCOE ANALYSIS AI TEXT FEEDBACK

Build an Excel model estimating costs for NY gas plants under doubled (\$7.28/MMBtu) and tripled (\$10.92/MMBtu) natural gas prices from \$3.64/MMBtu baseline. Compare current simple cycle (11,838 Btu/kWh heat rate) vs repowered combined cycle (6,300 Btu/kWh), scaling to 5,200 MW retired capacity under CLCPA. Include annual fuel costs, Cap-and-Invest taxes, and break-even repowering investment over 10 years with charts

Now I have all the data I need. Let me build the model:

- *RGGI/NYCI carbon price: ~\$25/short ton (Q1 2026 clearing price), with NYCI scenario of \$25–\$50/ton*
- *CO₂ emission factor: 53.06 kg CO₂/MMBtu natural gas*
- *CC repowering capex: \$1,800–\$2,500/kW (using \$2,200/kW midpoint for NY)*
- *Capacity: 5,200 MW*

The source/notes column (F) has descriptive text that contains formula-like characters (=, ×, ,) causing Excel to try parsing them as formulas. I need to force those cells to be text.

Zero errors across 439 formulas. Let me share the file.

Zero formula errors across 439 live calculations. Here's what's built:

Model Structure (5 Sheets)

Summary (Sheet 1)

Dashboard with a full KPI table linking all 6 technology/scenario combinations — Annual Fuel Cost, Cap-and-Invest Tax, Fixed/Variable O&M, Total Annual Cost (\$M), CC Savings, and LRMC (\$/MWh). Sheet navigator with clickable hyperlinks.

Assumptions

All inputs color-coded to financial modeling convention: blue = hardcoded input, black = formula, green = cross-sheet link. Yellow-highlighted cells are the key sensitivity levers — gas prices, capacity factor, WACC, capex/kW. Sourced inputs include:

- *CO₂ factor: 53.06 kg/MMBtu (EPA/IPCC)*
- *RGGI/NYCI carbon price: \$25.00/short ton (Q1 2026 RGGI clearing price via QC Intel)*
- *CC repowering capex: \$2,200/kW midpoint*

Annual Cost Model

Side-by-side comparison of all 3 gas price scenarios × 2 technologies, broken out by: Annual Fuel Cost, Cap-and-Invest Tax, Fixed O&M, Variable O&M — both in \$M and \$/MWh (LRMC).

Break-Even Analysis

10-year year-by-year NPV table for all 3 scenarios, with gas and carbon prices escalating annually (2% and 5% respectively). Each year shows discounted savings, cumulative NPV, remaining capex to recover, and a break-even flag (✓).

Charts (4 charts)

- 1. Grouped bar — Annual Fleet Cost \$M by scenario (SC vs CC)*
- 2. Grouped bar — LRMC \$/MWh by scenario*
- 3. Line chart — 10-year cumulative NPV savings vs. total capex threshold (all 3 scenarios)*
- 4. Bar — Annual CC savings (\$M) by scenario*

To run a sensitivity, change any blue or yellow-highlighted cell in Assumptions — everything recalculates automatically.

NY_Gas_Plant_Cost_Modelv1

Extend the model to compare repowering economics against a battery storage alternative at \$300–\$400/kWh for the 5,200 MW retired CLCPA capacity, using the same 10-year NPV framework

Good data gathered. Key parameters locked in:

- BESS capex: \$300–\$400/kWh (user-specified), aligns with NREL 2025 benchmark of \$334/kWh for 4-hour systems*
- Duration: 4-hour (industry standard for peaker replacement)*
- Fixed O&M: \$15–\$25/kW-yr; using \$18/kW-yr midpoint*
- Degradation: ~2%/year capacity fade, augmentation at Year 6*
- No fuel cost or carbon tax (zero-emission dispatch)*
- Power: 5,200 MW → Energy: 20,800 MWh at 4-hour duration*

The variable is used before assignment. I need to define CAPEX_TOTAL_CELL before the loop that uses it.

Two categories of issues:

- 1. Notes cells starting with = in Assumptions — same fix as before (strip leading =)*

2. *BESS Cost Model has nested = inside formulas like =C22-(=Assumptions!...) — the aref() helper wraps in = but the outer formula already has =*
3. *Summary rows E39-F41 all point to same cell — the savings references need to be per tier*

Two issues: >= instead of >= (stray =), and the label prefix "BESS BESS". Let me fix all of these:

Zero errors across 888 formulas.

Zero errors, 888 live formulas. Here's what was added:

New Sheets (3 added)

Assumptions — BESS Extension Block

New section appended with 18 BESS-specific inputs, yellow-highlighted on the key levers:

- *Installed cost: \$300 / \$350 / \$400/kWh (user range)*
- *Duration: 4 hours → 20,800 MWh fleet energy at 5,200 MW*
- *Fixed O&M: \$18/kW-yr (NREL ATB 2025, NextG Power)*
- *Degradation: 2%/yr; augmentation at Year 6 @ 50% of initial \$/kWh*
- *ITC: 30% (IRA 2022 standalone storage) → reduces effective BESS capex to ~\$5,762M at \$350/kWh mid vs. ~\$11,440M for CC repowering*

BESS Cost Model

- *CapEx summary table for all 3 cost tiers (gross → ITC deduction → effective net)*
- *Annual cost avoidance vs Simple Cycle by gas price scenario: BESS eliminates 100% of fuel cost and Cap-and-Invest carbon tax, plus captures O&M delta*
- *Annual BESS own cost shown separately (O&M only — no fuel, zero carbon tax)*

3-Way Comparison

The core analytical sheet: year-by-year 10-year NPV cumulative savings for all three technologies (SC baseline → CC repowering; SC baseline → BESS at \$300/\$350/\$400/kWh) under all three gas price scenarios, with break-even flags (✓) for each. Key dynamic: BESS advantage widens at higher gas prices because it avoids the full SC heat rate (11,838 Btu/kWh), while CC only partially reduces it to 6,300 Btu/kWh.

Two New Charts

- *Line chart: 10-year cumulative NPV trajectory — CC Repowering vs BESS (3 tiers) + capex threshold lines, at baseline gas price*

- *Grouped bar: Year-10 cumulative NPV savings for CC vs BESS mid at all 3 gas scenarios*

The ITC rate (currently 30%) is a yellow-flagged cell in Assumptions — adjust it if IRA standalone storage rules change or NY adder credits apply.

NY_Gas_Plant_Cost_Modelv2

What is the 40 year cost of gas plant repowering compared with the cost of implementing the CLCPA in NY State over the next 60 years

Research & Analysis Plan

Scope: 40-year gas plant repowering costs vs. 60-year CLCPA total program costs for NY State

Research Phase

- *Gas plant repowering (40-year): Extend the existing model's CC repowering capex, O&M, fuel costs, and carbon costs over 40 years — leveraging the 5,200 MW assumption, heat rate data, and NYCI/carbon price trajectory already built*
- *CLCPA 60-year total cost: Pull authoritative estimates for each major CLCPA program category:*
 - *Offshore wind (9,000 MW by 2035)*
 - *Onshore wind and solar buildout*
 - *Transmission upgrades (CHPE, Clean Path NY, etc.)*
 - *Battery storage deployment targets (6,000 MW)*
 - *Grid reliability / dispatchable backup*
 - *Electrification of buildings, transportation, industry*
 - *Policy administration, incentive programs, ratepayer impacts*
 - *Sources: NYSERDA, CESA, Brattle Group, CBO, academic studies*

Deliverable

- *Structured Markdown analysis with sourced cost estimates in organized tables*
- *Side-by-side 40-year NPV comparison where feasible*
- *Key caveats on methodology, discount rates, and definitional scope differences*
- *All figures cited to primary sources*

Model how the OSW+BEES vs gas CC crossover shifts if BESS duration drops from 4-hour to 6- or 8-hour to meet NYISO ICAP accreditation under stricter capacity rules

Good research haul. Key NYISO findings to embed in the model:

- **Current rule (2025):** 4-hour minimum for full ICAP accreditation. 2-hour gets 90% DAF (Duration Adjustment Factor) for <1,000 MW penetration, dropping to 75% above that.
- **The PLW trigger:** When duration-limited resources exceed 1,000 MW, NYISO shifts the Peak Load Window from 6-hour to 8-hour, requiring 8 hours for 100% accreditation.
- **DAF table:** 4hr = 90% DAF (below 1,000 MW threshold) / 75% above; 6hr = 100% / 90%; 8hr = 100% / 100%.
- **2025 DCR shift:** NYISO replaced the gas turbine peaker with a 2-hour battery as the reference technology — but this creates downward price pressure on capacity, making longer-duration BESS even more important for revenue adequacy.
- **CLCPA context:** 11,260 MW of storage needed, with 5-7-hour durations prominent in studies.

Now build the extension script — a patch that adds a new "BESS Duration Sensitivity" sheet and a "Duration Crossover" sheet to the existing workbook:

I have all the row numbers I need. Now I'll write the patch script that adds two new sheets to the existing workbook: BESS Duration Sensitivity and Duration Crossover. The existing sheets stay untouched.

I'll pick up exactly where we left off — running the duration patch script, then recalculating and validating.

First, let me check the current state of the patch script and workbook:

Good — all files present. Let me read the duration script to verify it before running:

Script looks solid. One issue I can see: line 299 builds the "effective ICAP" string with an f-string that uses = prefix, which openpyxl will parse as formulas. I need to fix those cells before running. Let me also check the note cells (lines 409-413) for the same = prefix issue, then patch and execute:

Now also remove the stale val items for columns 5 and 6 from the loop list to avoid the dead code path, and fix the PLW note-cell strings (which may contain \n — fine for text, no = prefix):

Good. Now run the script:

Script ran cleanly — 8 sheets now in the workbook. Running recalc:

Zero errors across all 963 formulas. Now spot-check the key LCOE values from the new sheets:

Two issues I can see clearly:

1. *High \$400/kWh rows show ~\$0.01 instead of ~\$19-20/MWh — the BESS gross formula for `bess_hi` uses `aref(A_bess_hi) = Assumptions!D64`. Need to verify what's in D64.*
2. *OSW+BESS LCOE shows only the BESS increment, not the full OSW+BESS total — the formula is computing only BESS costs, not the full OSW+BESS stack. The `data_only=True` read is seeing cached values from before recalc, but the numbers are wrong regardless — \$17 is clearly just the BESS portion, not \$230+.*

Let me diagnose both issues:

Now I can see the root cause clearly — the Assumptions row numbers are all off by 4 from what the script expected. The context summary had them mapped as:

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But the actual workbook has:

- *Row 47 = WACC (0.08) — not row 43*
- *Row 60 = BESS hours (4)*
- *Row 61 = BESS low \$300*
- *Row 62 = BESS mid \$350*
- *Row 63 = BESS high \$400*
- *Row 64 = ITC (0.30) — not \$400*
- *Row 52 = OSW capex \$5,500/kW*

The script used row 47 for OSW capex, 48 for FOM, 49 for CF, 51 for OSW MW, 54 for O&M esc, 43 for WACC — all wrong. I need to build a corrected row map:

Now I have the complete correct row map. The script had every reference shifted. Here are the correct values:

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This explains everything: WACC was reading \$25 (NYCI price), OSW capex was reading 0.08 (WACC), BESS high was reading ITC 0.30, etc. The formula calculated only a tiny BESS-cost fragment using these wrong inputs. I need to rewrite the patch script with the correct row map:

Now also need to check the Gas Plant LCOE sheet row map since the existing model's rows may have shifted too:

Gas rows confirmed correct. Now checking OSW sheet — the 4-hr BESS LCOE values are in cols 8-11 (10yr=col8=316.05? Wait, those are rows 27-29 cols G-J in 1-indexed. Let me check exactly:

- *Northport Mid 20yr = 237.39 ✓ (matches context summary)*
- *OSW standalone row 19 = 258.76/190.73/173.17/167.13 ✓*

And OSW sheet columns: 10yr=col3(C), 20yr=col4(D), 30yr=col6(F), 40yr=col7(G) — but OSW+BESS 4hr is in cols 8-11 = H-K per the context. Let me verify:

The OSW+BESS LCOE in the existing sheet (row 27, Northport Lo): col H=316.05, col I=231.27, col J=215.03, col K=207.02. But the crossover sheet pulls from OSW_H_COL = {10:3, 20:4, 30:6, 40:7} for standalone, which matches col C=258.76, D=190.73, F=173.17, G=167.13 ✓.

Now also I see the existing OSW+BESS 4hr LCOE in OSW sheet cols 8-11 (H-K): 10yr=316.05, 20yr=231.27, 30yr=215.03, 40yr=207.02. The dur_lcoe_refs in the new script however points to the new BESS Duration Sensitivity sheet cells, not the old OSW sheet. That's correct — we're computing fresh from formulas using the corrected row map.

Also note: the Gas Plant LCOE sheet has Barrett at rows 13-17 (not 13-16 as in GAS_ROWS), and PJ at rows 19-23 (not 18-21). Let me fix the GAS_ROWS map:

Also need to check the OSW_H_COL map — the standalone row 19 has 10yr=col3=258.76, 20yr=col4=190.73, 30yr=col6=173.17, 40yr=col7=167.13. But from the output, the OSW sheet column headers say "30-Year (+life" at col6 and "40-Year (2nd w" at col7. The script has OSW_H_COL = {10:3, 20:4, 30:6, 40:7} — that's correct.

Now run the corrected script:

Zero errors. Now spot-check the LCOE values:

The numbers are now economically coherent. Let me validate them:

Sanity checks:

- *4hr Mid 20yr = \$237.39 ✓ matches existing OSW sheet (context summary confirms \$237.39)*
- *6hr Mid 20yr = \$258.79 — increment from 4hr = \$21.41/MWh per 2hrs (Northport; context estimated ~\$16-21, this is in range ✓)*
- *8hr Mid 20yr = \$280.20 — another +\$21.41 ✓ (symmetric, as expected)*
- *Gas CC 4× with carbon = \$232.50 ✓ matches verified table*
- *At 4× gas, Δ (4hr Mid) = -\$4.9 → gas slightly cheaper than OSW+BESS mid 4hr ✓ (context said "within ~\$5", confirmed)*
- *At 4× gas, Δ (4hr Lo) = +\$1.2 → gas CC actually more expensive than OSW+BESS Lo 4hr ✓ (crossover achieved at low BESS price)*

One issue: the 6hr Low and 8hr Low show the same LCOE (\$267.97 for both in the sensitivity sheet). Let me check:

The formulas are correct — 6hr uses 7200 MWh and 8hr uses 9600 MWh as expected. The data_only=True output earlier showing them equal was a display artifact from the table layout (the in_incr detection logic was showing the wrong rows). Let me verify the actual saved values:

All 9 LCOE values match Python reference calculations to the cent. Gas CC values unchanged. The model is clean. Share it:

Done. 963 formulas, zero errors. Here's what the two new sheets contain and what they tell you:

What Was Added

Sheet 7: "BESS Duration Sensitivity"

Per-plant LCOE table — 3 plants × 3 durations × 3 BESS prices × 4 horizons = 108 LCOE cells, all live formulas cross-referencing Assumptions. Also includes the NYISO DAF accreditation table and BESS CapEx breakdown (gross / ITC savings / net).

Sheet 8: "Duration Crossover"

20-year crossover shift table with Gas CC (w/ and w/o carbon) vs OSW+BESS at all durations, plus:

- Delta table (Gas – OSW+BESS at each duration/price/plant)*
- Increment table with embedded bar chart*

Key Findings

LCOE increment per additional 2 hours of BESS duration (Northport, 20-year):

<i>BESS Price</i>	<i>4hr LCOE</i>	<i>6hr LCOE</i>	<i>8hr LCOE</i>	<i>Cost per 2hr step</i>
<i>Low \$300/kWh</i>	<i>\$231.27</i>	<i>\$249.62</i>	<i>\$267.97</i>	<i>+\$18.35/MWh</i>
<i>Mid \$350/kWh</i>	<i>\$237.39</i>	<i>\$258.79</i>	<i>\$280.20</i>	<i>+\$21.41/MWh</i>
<i>High \$400/kWh</i>	<i>\$243.50</i>	<i>\$267.97</i>	<i>\$292.43</i>	<i>+\$24.46/MWh</i>

Crossover shift impact (Northport, Mid BESS, 20yr, with carbon):

Gas Scenario Gas CC OSW+4hr OSW+6hr OSW+8hr

1× \$4.50	\$132	\$237	\$259	\$280
2× \$9.00	\$166	\$237	\$259	\$280
3× \$13.50	\$199	\$237	\$259	\$280
4× \$18.00	\$233	\$237	\$259	\$280

Bottom line: Stricter NYISO ICAP rules that push BESS from 4hr to 8hr add ~\$43/MWh to the OSW+BESS stack at Mid price — widening the gap vs gas CC by roughly 20%, and pushing the effective crossover point beyond any modeled gas price scenario. At 4× gas with 4hr BESS, OSW+BESS Lo just barely achieves crossover (+\$1.2/MWh delta). At 8hr BESS, gas would need to exceed ~\$22/MMBtu (6× current) for crossover at the Mid price tier.

Build an Excel model estimating costs for NY gas plants under doubled (\$7.28/MMBtu) and tripled (\$10.92/MMBtu) natural gas prices from \$3.64/MMBtu baseline. Compare current simple cycle (11,838 Btu/kWh heat rate) vs repowered combined cycle (6,300 Btu/kWh), scaling to 5,200 MW retired capacity under CLCPA. Include annual fuel costs, Cap-and-Invest taxes, and break-even repowering investment over 10 years with charts

Now I have all the data I need. Let me build the model:

- **RGGI/NYCI carbon price: ~\$25/short ton (Q1 2026 clearing price), with NYCI scenario of \$25–\$50/ton**
- **CO2 emission factor: 53.06 kg CO2/MMBtu natural gas**
- **CC repowering capex: \$1,800–\$2,500/kW (using \$2,200/kW midpoint for NY)**
- **Capacity: 5,200 MW**

The source/notes column (F) has descriptive text that contains formula-like characters (=, ×, ,) causing Excel to try parsing them as formulas. I need to force those cells to be text.

Zero errors across 439 formulas. Let me share the file.

Zero formula errors across 439 live calculations. Here's what's built:

Model Structure (5 Sheets)

Summary (Sheet 1)

Dashboard with a full KPI table linking all 6 technology/scenario combinations — Annual Fuel Cost, Cap-and-Invest Tax, Fixed/Variable O&M, Total Annual Cost (\$M), CC Savings, and LRMC (\$/MWh). Sheet navigator with clickable hyperlinks.

Assumptions

All inputs color-coded to financial modeling convention: blue = hardcoded input, black = formula, green = cross-sheet link. Yellow-highlighted cells are the key sensitivity levers — gas prices, capacity factor, WACC, capex/kW. Sourced inputs include:

- *CO₂ factor: 53.06 kg/MMBtu (EPA/IPCC)*
- *RGGI/NYCI carbon price: \$25.00/short ton (Q1 2026 RGGI clearing price via QC Intel)*
- *CC repowering capex: \$2,200/kW midpoint*

Annual Cost Model

Side-by-side comparison of all 3 gas price scenarios × 2 technologies, broken out by: Annual Fuel Cost, Cap-and-Invest Tax, Fixed O&M, Variable O&M — both in \$M and \$/MWh (LRMC).

Break-Even Analysis

10-year year-by-year NPV table for all 3 scenarios, with gas and carbon prices escalating annually (2% and 5% respectively). Each year shows discounted savings, cumulative NPV, remaining capex to recover, and a break-even flag (✓).

Charts (4 charts)

1. *Grouped bar — Annual Fleet Cost \$M by scenario (SC vs CC)*
2. *Grouped bar — LRMC \$/MWh by scenario*
3. *Line chart — 10-year cumulative NPV savings vs. total capex threshold (all 3 scenarios)*
4. *Bar — Annual CC savings (\$M) by scenario*

To run a sensitivity, change any blue or yellow-highlighted cell in Assumptions — everything recalculates automatically.

NY_Gas_Plant_Cost_Modelv1

Extend the model to compare repowering economics against a battery storage alternative at \$300–\$400/kWh for the 5,200 MW retired CLCPA capacity, using the same 10-year NPV framework

Good data gathered. Key parameters locked in:

- *BESS capex: \$300–\$400/kWh (user-specified), aligns with NREL 2025 benchmark of \$334/kWh for 4-hour systems*
- *Duration: 4-hour (industry standard for peaker replacement)*

- *Fixed O&M: \$15–\$25/kW-yr; using \$18/kW-yr midpoint*
- *Degradation: ~2%/year capacity fade, augmentation at Year 6*
- *No fuel cost or carbon tax (zero-emission dispatch)*
- *Power: 5,200 MW → Energy: 20,800 MWh at 4-hour duration*

The variable is used before assignment. I need to define CAPEX_TOTAL_CELL before the loop that uses it.

Two categories of issues:

1. *Notes cells starting with = in Assumptions — same fix as before (strip leading =)*
2. *BESS Cost Model has nested = inside formulas like =C22-(=Assumptions!...) — the aref() helper wraps in = but the outer formula already has =*
3. *Summary rows E39-F41 all point to same cell — the savings references need to be per tier*

Two issues: >== instead of >= (stray =), and the label prefix "BESS BESS". Let me fix all of these:

Zero errors across 888 formulas.

Zero errors, 888 live formulas. Here's what was added:

New Sheets (3 added)

Assumptions — BESS Extension Block

New section appended with 18 BESS-specific inputs, yellow-highlighted on the key levers:

- *Installed cost: \$300 / \$350 / \$400/kWh (user range)*
- *Duration: 4 hours → 20,800 MWh fleet energy at 5,200 MW*
- *Fixed O&M: \$18/kW-yr (NREL ATB 2025, NextG Power)*
- *Degradation: 2%/yr; augmentation at Year 6 @ 50% of initial \$/kWh*
- *ITC: 30% (IRA 2022 standalone storage) → reduces effective BESS capex to ~\$5,762M at \$350/kWh mid vs. ~\$11,440M for CC repowering*

BESS Cost Model

- *CapEx summary table for all 3 cost tiers (gross → ITC deduction → effective net)*
- *Annual cost avoidance vs Simple Cycle by gas price scenario: BESS eliminates 100% of fuel cost and Cap-and-Invest carbon tax, plus captures O&M delta*
- *Annual BESS own cost shown separately (O&M only — no fuel, zero carbon tax)*

3-Way Comparison

The core analytical sheet: year-by-year 10-year NPV cumulative savings for all three technologies (SC baseline → CC repowering; SC baseline → BESS at \$300/\$350/\$400/kWh) under all three gas price scenarios, with break-even flags (✓) for each. Key dynamic: BESS advantage widens at higher gas prices because it avoids the full SC heat rate (11,838 Btu/kWh), while CC only partially reduces it to 6,300 Btu/kWh.

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All 9 LCOE values match Python reference calculations to the cent. Gas CC values unchanged. The model is clean. Share it:

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What Was Added

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Per-plant LCOE table — 3 plants × 3 durations × 3 BESS prices × 4 horizons = 108 LCOE cells, all live formulas cross-referencing Assumptions. Also includes the NYISO DAF accreditation table and BESS CapEx breakdown (gross / ITC savings / net).

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- *Delta table (Gas – OSW+BESS at each duration/price/plant)*
- *Increment table with embedded bar chart*

Key Findings

LCOE increment per additional 2 hours of BESS duration (Northport, 20-year):

<i>BESS Price</i>	<i>4hr LCOE</i>	<i>6hr LCOE</i>	<i>8hr LCOE</i>	<i>Cost per 2hr step</i>
<i>Low \$300/kWh</i>	<i>\$231.27</i>	<i>\$249.62</i>	<i>\$267.97</i>	<i>+\$18.35/MWh</i>
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Crossover shift impact (Northport, Mid BESS, 20yr, with carbon):

<i>Gas Scenario</i>	<i>Gas CC</i>	<i>OSW+4hr</i>	<i>OSW+6hr</i>	<i>OSW+8hr</i>
<i>1× \$4.50</i>	<i>\$132</i>	<i>\$237</i>	<i>\$259</i>	<i>\$280</i>
<i>2× \$9.00</i>	<i>\$166</i>	<i>\$237</i>	<i>\$259</i>	<i>\$280</i>
<i>3× \$13.50</i>	<i>\$199</i>	<i>\$237</i>	<i>\$259</i>	<i>\$280</i>
<i>4× \$18.00</i>	<i>\$233</i>	<i>\$237</i>	<i>\$259</i>	<i>\$280</i>

Bottom line: Stricter NYISO ICAP rules that push BESS from 4hr to 8hr add ~\$43/MWh to the OSW+BESS stack at Mid price — widening the gap vs gas CC by roughly 20%, and pushing the effective crossover point beyond any modeled gas price scenario. At 4× gas with 4hr BESS, OSW+BESS Lo just barely achieves crossover (+\$1.2/MWh delta). At 8hr BESS, gas would need to exceed ~\$22/MMBtu (6× current) for crossover at the Mid price tier.

APPENDIX D

Twenty-three Questions were posed to AI. Notice the 2 -3 X planned budgets due to delays. The CLCPA's design with "Ideal Supply Chains" as noted by AI did account for this and numerous other issues..

" Official plans assume perfect supply chains that do not exist." In a response to question 9.

And the kicker: "Full 2040 zero-emission dream dies under \$4k household shocks."

This is exactly what happened in Ontario 8 years ago with their "Green" plan which I mentioned to Chairman Rhodes in January 2020. If you overreach, you end up with nothing.

Rich

1 - Can NY State ever install enough wind and solar to offset its electric and thermal loads?

Probably yes in theory, but not as a simple 1-to-1 annual energy match from wind and solar alone. New York can likely generate enough annual renewable electricity and thermal energy in a highly electrified future, but it would require major overbuild, transmission expansion, storage, demand flexibility, and likely some firm zero-carbon backup for the hours and weeks when wind and solar are low.

Electricity

For electricity, the main issue is not just total yearly megawatt-hours; it is matching demand every hour. New York already has a sizable pipeline of clean projects, but current plans and commentary suggest the state would need much more buildout to cover both rising demand and reliability needs.

Thermal load

Thermal load is the harder part, because heating is seasonal and peaks in winter when solar output is weaker. To offset electric plus thermal loads, New York would need widespread electrification of heating, very large amounts of heat pumps and thermal storage, and likely some combination of long-duration storage, transmission imports, geothermal, biomass, or other firm clean sources.

Main constraint

*The biggest constraint is **reliability**, not just total installed capacity. Even analyses that are supportive of renewables note that high shares of wind and solar can require nearly complete backup or very large storage to keep the system balanced through low-wind, low-sun periods.*

Practical conclusion

So the answer is: possibly yes over time, but only with a much broader clean-energy system than wind and solar alone. If the question is whether New York can someday run its whole economy on enough renewable generation plus storage and grid upgrades, that is plausible; if the question is whether wind and solar by themselves can continuously offset all electric and thermal loads, that is much less likely.

2 - How much storage would be required for the system above?

*New York State's plans target **6 GW of storage by 2030** (mostly 2–8 hour duration batteries) and project needs of **12–17 GW by 2040–2050** to support high renewable penetration, but covering full electric and thermal loads with wind/solar would likely require **much more**—potentially **20+ GW of short-duration storage plus several GW of long-duration storage** (10–100+ hours).*

Short-term targets

Current policy focuses on 6 GW total storage to firm up the grid as renewables grow toward 70% by 2030. This includes bulk (large-scale), distributed, and residential batteries, with about 1.3 GW already under contract as of 2024.

For full offset

To reliably match wind/solar variability for all loads (including seasonal heating peaks), studies imply needs far beyond today's targets:

- *Short-duration (4–8 hours): 10–20 GW to handle daily cycles.*
- *Long-duration (10–100 hours): 5–10 GW+ for multi-day lulls, plus seasonal shifts via pumped hydro or emerging tech.*

Key limits

Even aggressive builds face land, supply-chain, and cost hurdles; true 100% offset would also need massive overbuild of generation, grid upgrades, and demand response. Storage alone cannot solve winter solar droughts without firm clean backups.

3 - How often would the current storage technologies have to be replaced ?

*Current grid storage technologies, mainly lithium-ion batteries (LFP and NMC chemistries), would need replacement every 10–20 years depending on cycle frequency, depth of discharge (DoD), and grid duty. In a high-renewable NY system with daily cycling for wind/solar balancing, expect replacements every **12–15 years** on average.*

Lifespan details

- **Cycle life:** 3,000–10,000 full cycles at 80–100% DoD before capacity drops to 80%. Daily 1–2 cycles (common for grid storage) = 10–15 years.
- **Calendar aging:** Even idle, chemical degradation limits to 10–20 years; heat/grid stress accelerates this to 12 years typical.
- **Examples:** LFP grid batteries warranted 10 years/3,500–6,000 cycles; heavy use (2 cycles/day) halves calendar life to ~8–12 years.

Replacement math for NY

For 20–30 GW storage cycled daily: **full fleet replacement every 12–15 years**, costing \$50–150B per cycle (at \$200–400/kWh). Over 60 years, that's **4–5 full replacements** vs. nuclear's near-zero, compounding renewables' long-term costs.flux

4 - What would a system like that cost with all of the required overbuilds?

A full wind/solar system for New York State, with required overbuild (2–4x nameplate capacity) and storage (20+ GW short-duration plus 5–10 GW long-duration), would likely cost **\$300–600 billion** in capital expenditures through 2040–2050, or roughly **\$10–20 billion annually** spread over decades, depending on technology costs, scale, and transmission.

Cost components

- **Generation overbuild:** 100–200 GW wind/solar at \$1–2 million/MW = **\$100–400 billion**. Overbuilding offsets low capacity factors (20–40%).
- **Storage:** 20 GW short-duration (4–8 hr) at ~\$300/kWh + 5–10 GW long-duration at \$100–200/kWh = **\$100–200 billion**.
- **Transmission/grid upgrades:** **\$50–100 billion** for new lines to move power from upstate/offshore to NYC.

Key assumptions

Costs use 2025–2026 benchmarks where utility-scale solar/wind fell to \$0.8–1.5M/MW and batteries to \$200–400/kWh (with overbuild factors). Some modeling shows long-duration storage could cut total system costs by 6–30% vs. short-duration only, by reducing excess generation needs. True lifetime costs (O&M, replacements) could add 20–50% more, but falling prices might offset this.

Comparison

New York's current annual electricity spend is ~\$20–25 billion; a full transition might raise system costs initially but stabilize or lower them long-term if fossil backups are phased out efficiently. Critics argue reliability tradeoffs make it uneconomic without subsidies.

5 - What would it cost to rewire NY City to electrify Thermal Loads

*Rewiring New York City to fully electrify thermal loads (heating, hot water) would cost **\$100–300 billion** citywide over 20–30 years, depending on building efficiency upgrades, heat pump scale, and grid reinforcements. This estimate draws from NYC-specific studies on building retrofits, panel upgrades, and partial electrification pilots.*

Main costs

- **Heat pumps + weatherization per building:** \$15,000–\$50,000 for residential (multi-family averages \$20k–\$40k/unit), scaling to **\$50–150 billion** for 1–2 million NYC buildings.
- **Electrical upgrades (panels, wiring, submeters):** \$5,000–\$20,000 per home or \$2–5 billion per 100k units; citywide **~\$30–80 billion** for service upgrades to 200–400 amp panels and new circuits.
- **Grid/substation reinforcements:** **\$20–70 billion** to handle peak winter electric loads doubling from current levels.

Key factors

Costs assume 85% building electrification per NY Climate Leadership goals, with subsidies covering 30–50% for low-income units. Lifecycle savings from efficiency could offset 20–40% of upfront costs, but older multifamily housing drives higher expenses. Full rollout by 2050 spreads the burden to ~\$5–10 billion/year.

6 - Is there enough labor to execute the electrification of NY City?

No, there likely isn't enough skilled labor today to execute full NYC electrification without major workforce expansion, training programs, and time delays. New York State has about 120,000 workers in building decarbonization roles like HVAC, insulation, and electrical upgrades, but NYC's scale—millions of multifamily units needing heat pumps and rewiring—would overwhelm this amid broader shortages.

Current capacity

Statewide figures show 73,000 in residential and 48,000 in commercial building work, with potential growth to 400,000 by 2050. Yet NYC faces acute HVAC technician and electrician shortages, with demand outpacing supply due to retirements and competition from infrastructure megaprojects.

Challenges

- *Construction labor in NYC dropped to 247,000 workers recently, strained by aging workforce and low youth entry.*
- *Electrification requires specialized skills (heat pumps, 200–400A panels), but training lags; programs like TREC aim to certify thousands more yet can't scale instantly.*

Path forward

Initiatives like union partnerships, IRA-funded training (\$200M for HVAC/electrical), and employer coalitions could triple capacity over a decade, but full rollout by 2050 would need 5–10x current NYC-specific labor—possible with immigration, apprenticeships, and tech like modular retrofits, but not without 5–15 year delays or higher costs from labor premiums.

7 - Are there enough transformers to execute the NY City transition ?

No, there aren't enough transformers available today to execute NYC's full electrification transition without years of delays, massive cost premiums, and supply chain fixes. A nationwide transformer crisis—driven by aging stock, exploding demand from electrification/AI/data centers, and limited manufacturing—directly threatens New York City's grid upgrades for doubled winter heating loads.

Supply crunch

- *Lead times for distribution transformers ballooned from 3–6 months (2019) to 2–4 years (2026), with prices up 4–6x since 2022.*
- *U.S. needs **twice as many** high-voltage units just to replace old ones, let alone add for new loads; over half of 60–80 million existing transformers are 33+ years old.*
- *NYC-specific: ConEd and National Grid manage thousands of substations, but recent installs (e.g., massive 345,000 lb units) highlight delivery bottlenecks for even single projects.*

NYC impact

*Electrifying thermal loads could double peak electric demand, requiring **thousands of new/upsized transformers** for panels, risers, and substations. Current shortages already block new customer connections and strain reliability; full rollout would overwhelm this without heroic measures like rationing or peaker plants. [from prior]*

Fixes underway, but slow

New U.S. factories (e.g., Siemens \$150M NC plant by 2027, Cleveland-Cliffs WV hub) aim to add capacity, but won't match demand until 2028–2030. NYC would face sequenced rollouts, higher bills from scarcity pricing, and likely emergency imports (even from China, despite security risks).

8 - Is there enough labor to implement the CLCPA?

No, there is not enough labor currently available to fully implement the CLCPA's aggressive targets on schedule. New York has about 184,000 clean energy workers as of 2024, but the plan demands hundreds of thousands more by 2030 for renewables, building electrification, grid upgrades, and related work—far outpacing supply amid national shortages in electricians, HVAC techs, and welders.

Current gaps

NY's workforce grew by ~6,000–8,000 jobs yearly recently, but CLCPA projections call for 200,000+ new roles by 2030 (e.g., solar installers, heat pump specialists). Training programs have certified 40,000 since 2018, yet job creation lags—NYC added just 2,184 green jobs in 2023 despite promises.

Broader shortages

Key trades face deficits: 40,000+ electricians needed nationally for renewables alone, plus welders and turbine techs. NYC's multifamily retrofits amplify this, competing with infrastructure megaprojects.

Mitigation efforts

\$320M in state funding boosts training (e.g., NYSERDA pathways), aiming for scaled apprenticeships and union partnerships. Still, full ramp-up to meet 70% renewables + electrification would take 10–20 years, likely delaying CLCPA beyond 2040.

9 - With the issues above, how many years will it take for NY State to make the transition?

No, NY State cannot complete a full electrification transition by its official 2040–2050 targets; realistic timelines stretch to 20–40 years (2045–2065) due to transformer shortages (2–4 year lead times), labor gaps (needing 5–10x current HVAC/electrical workforce), and massive scale

*(\$400–900B total from generation overbuild, storage, rewiring, grid). **Official plans assume perfect supply chains that do not exist.***

Binding constraints

- ***Transformers:*** Nationwide crisis means NYC's substation/panel upgrades for doubled winter peaks face **5–10 year delays** alone; new factories won't scale until 2028–2030.
- ***Labor:*** Only ~120k workers statewide for millions of heat pumps/rewirings; training ramps to 400k by 2050 still leaves NYC short by factor of 3–5.
- ***Parallel build:*** Renewables (100–200 GW), storage (25+ GW), and retrofits cannot happen simultaneously without rationing projects.

Phased reality

- ***By 2030:*** New buildings all-electric (already starting 2026), 20–30% existing retrofits, 6 GW storage—meets partial goals but not full loads.
- ***By 2040:*** 50–70% electrified, if supply chains improve; NYC grid hits limits **without heroic imports/permits.**
- ***Full transition:*** 2055–2065, with 20–30% still on gas/hybrids due to multifamily grid bottlenecks.

*New York's history shows electrification took **decades** even without modern shortages; this will too, likely costing 2–3x planned budgets from delays.*

10 - Is there any dispatchable emission free resource currently available that will support NY States Climate Plan?

*Yes, **nuclear power** is the primary dispatchable emission-free resource currently available to support New York State's Climate Leadership and Community Protection Act (CLCPA) goals of 70% renewables by 2030 and 100% zero-emission electricity by 2040. Existing upstate nuclear plants (e.g., Ginna, FitzPatrick, Nine Mile Point) already provide about 25–30% of NY's electricity reliably, and relicensing plus small modular reactors (SMRs) are key to filling the 20–40 GW "dispatchable emissions-free resource" (DEFER) gap identified by NYISO for low wind/solar periods.*

Existing nuclear

- *Four plants supply ~6 GW firm capacity, running at 90%+ factors year-round regardless of weather.*

Context on capacity

These generate ~25–30% of NY's electricity (carbon-free), down from 5–6 GW peak when Indian Point (Westchester, 2+ GW) ran until 2021 closure. NYISO models cite ~6 GW "firm nuclear-equivalent" including hydro/life extensions, but actual reactors sum to 3.4 GW nameplate.

- *Zero lifecycle emissions (post-construction); can ramp/load-follow to balance intermittents.*
- *NYISO and DPS explicitly call it essential, alongside hydro (~6 GW, geographically limited).*

Emerging options

- *Advanced nuclear/SMRs: NYSERDA's 2024 blueprint targets deployment by 2030–35; scalable to 10+ GW without land/water constraints of renewables.*
- *Pumped hydro/geothermal: Minor expansions possible (e.g., 1–2 GW), but not at DEFR scale soon.*
- *Batteries (6 GW target by 2030) help daily but not multi-week lulls; hydrogen/biofuels unproven at grid scale.*

Why nuclear fits

Plans assume 20–40 GW DEFRs to avoid blackouts; nuclear is the only mature, proven tech today—others like fusion or iron-air batteries are 10+ years out. Without it, NY faces gas peakers or demand cuts.

11 - Is Nuclear Dispatchable and what is the timeframe to build 20 - 40 GW of them to support the climate plan ?

Yes, nuclear power is dispatchable. Modern nuclear plants can ramp output from 50–100% within hours, load-follow daily peaks, and provide firm capacity through weather-dependent lulls—making it a proven dispatchable emissions-free resource (DEFR) for NYISO grid balancing.

Build timeframe for 20–40 GW

25–50 years minimum (2050–2075), far beyond NY's 2040 zero-emission electricity target, due to regulatory, supply chain, and construction realities:

- *Recent U.S. precedent: Vogtle Units 3–4 took 15+ years and \$35B for ~2 GW; average large reactor: 10–15 years permitting + build.*
- *NY plans: Gov. Hochul ordered 1 GW (large reactor or SMRs) in June 2025 via NYPA—first new plant in decades, no timeline given, likely online 2035–2040 even optimistically.*

- **Scaling to 20–40 GW:** Would need 20–40 large reactors or 200–400 SMRs (300 MW each). SMRs promise 5–7 years but lack U.S. fleet deployment; first NY SMRs might hit 2035, but mass rollout faces NRC bottlenecks, uranium supply, skilled labor shortages, and local opposition.

Practical limits

NY's current 3.4–6 GW nuclear (Ginna, FitzPatrick, etc.) can be relicensed/life-extended to 2040–50, buying ~10–15 GW-equivalent time. But greenfield 20–40 GW exceeds U.S. total new nuclear since 1990 (~5 GW). Without streamlined permitting (unlikely post-Vogtle), NY falls back on gas/hydrogen peakers.

12 - If that much nuclear is needed, then why build the solar and wind?

Nuclear alone cannot meet NY's Climate Plan targets because the state's Climate Leadership and Community Protection Act (CLCPA) legally mandates **70% renewable electricity by 2030 and 9 GW offshore wind specifically**—solar and wind are required by statute, not optional, even if nuclear provides dispatchable backbone.

Legal requirements

- CLCPA defines "renewables" as hydro, wind, and solar—explicitly excluding nuclear despite its zero emissions.
- 2030: 70% from these sources (NY currently ~30–35% renewables + 25% nuclear).
- 2040: 100% zero-emission electricity, but the renewable carve-out forces wind/solar build regardless of cost or reliability.

Practical reasons

- **Complementarity:** Wind peaks evenings/nights (when solar dips); together they smooth daily variability better than either alone, reducing (but not eliminating) storage needs before nuclear/hydro firming.
- **Cost/land tradeoffs:** Solar/wind at \$1M/MW vs. nuclear \$6–10M/MW means cheaper marginal kWh from renewables today; NYSERDA models show 4 GW nuclear could cut excess solar/wind needs, saving \$1B+, but not replace them.
- **Political reality:** Renewables enjoy subsidies (IRA/OSC), public buy-in, and faster permitting (2–3 years vs. nuclear's 10–15); NYPA's plan prioritizes them despite critiques.

The catch

Critics like Keith Schue argue this misses the point: **nuclear should lead as DEFR (20–40 GW needed), with minimal wind/solar as supplement**—full renewables reliance risks blackouts and

\$trillions in overbuild/storage. But policy locks in solar/wind first, forcing nuclear as expensive afterthought.

13 - Removing the CLCPA's timeframe, which would be the better and cheaper system over a 60 year period?

Over a 60-year horizon without CLCPA's tight deadlines, a nuclear-heavy system would be cheaper and more reliable than one dominated by solar, wind, overbuild, and storage. Nuclear's 60–100 year lifespan, 90%+ capacity factor, and minimal system costs (no backups needed) yield lower lifetime LCOE (~\$80–130/MWh) versus firm renewables (~\$100–250/MWh including replacements every 20–30 years).

Cost comparison

<i>System</i>	<i>Capex (first 20 yrs)</i>	<i>60-yr LCOE</i>	<i>Replacements</i>	<i>Land/Transmission</i>
<i>Nuclear</i>	<i>\$6–10B/GW</i>	<i>\$80–130/MWh</i>	<i>Minimal (refueling)</i>	<i>Low</i>
<i>Solar/Wind + Storage</i>	<i>\$2–4B/GW (nameplate)</i>	<i>\$100–250/MWh</i>	<i>Every 20–30 yrs (\$trillions)</i>	<i>Massive</i>

Nuclear wins long-term: no degradation, no curtailment, full dispatchability. Renewables require 2–4x overbuild + storage cycling losses, driving higher system costs despite cheap upfront panels.

Reliability edge

Nuclear provides firm power 24/7/365 without weather dependence or multi-week lulls. A renewables-heavy grid needs backups (gas or endless storage), adding 20–50% to costs; nuclear grids (e.g., France) achieve 70–90% clean power stably.

Optimal mix

80% nuclear + 20% renewables/hydro minimizes costs at ~\$90/MWh over 60 years—leveraging nuclear baseload with cheap solar/wind peaks. Pure renewables fail economically past 50–60% penetration without heroic overbuild.

14 - If it has taken Australia 20 years to reach a point where utility rates are just starting to drop because of the renewable transition, how long will it take NY State to do it with four times the thermal load, 2% of the land for renewable installations, and 40% of the solar capacity factor and how much more expensive will it be?

NY State would likely take 80–150 years to see utility rates drop from its renewable transition, compared to Australia's ~20 years. Costs could end up 4–10x higher per MWh long-term.

Timeline scaling factors

- *Australia's path: Vast land (7.7M km²), high solar factor (~22%), minimal thermal electrification—reached wholesale price drops by 2026 after daytime solar overbuild.*
- *NY's constraints:*
 - *4x thermal load: Winter heating peaks double/triple electric demand (vs. Australia's milder climate).*
 - *2% land availability: Forces expensive offshore wind (2–4x onshore costs) and rooftop/distributed solar.*
 - *40% solar factor (~12% NY vs. ~25–30% Australia): Requires 2.5x more panels for equivalent output.*

These amplify overbuild (4–6x capacity), storage cycling, and grid costs exponentially.

Cost multiplier

<i>Factor</i>	<i>Australia</i>	<i>NY Impact</i>
<i>Land</i>	<i>Abundant</i>	<i>Offshore wind @ \$3–5M/MW (vs. \$1M onshore)</i>
<i>Solar</i>	<i>25% factor</i>	<i>2.5x panels needed @ \$1M/MW</i>
<i>Thermal</i>	<i>Low</i>	<i>Storage doubles for winter peaks</i>

Net LCOE \$50–80/MWh \$200–500/MWh firmed system

NY's urban density + policy delays (transformers, labor) push breakeven beyond 2100, with rates likely rising 100–200% first.

Australia's wholesale drops came from cheap solar flooding the grid; NY's winter-dominated load and land scarcity mean endless backups and replacements, pushing breakeven decades later at 3–8x the price.

15 - How much will rates rise before that 60 - 100 year timeframe?

NY residential electricity rates could rise 50–150% over the next 20–30 years (to 40–65¢/kWh by 2045–2050) before any potential stabilization or drop in the 2085+ timeframe, driven by CLCPA-mandated renewables, grid upgrades, and thermal electrification costs outpacing savings. Upstate households face the steepest hikes, with \$2,000–\$4,000 annual bill increases possible by 2030–2035 under full implementation.

Near-term trajectory (2026–2040)

- **2025–2027:** Already underway—NYSEG +9.9% (\$11/mo), National Grid +28% over 3 years (\$14–25/mo), RG&E +26%. Statewide average hit 27¢/kWh in 2025, 50% above U.S. average.
- **2030:** NYSERDA models warn of \$2,300–\$4,000/yr extra for households under cap-and-invest to hit targets, or 40–60% bill spikes from delivery charges alone.
- **2040:** Cumulative 100–150% rate hikes as thermal loads double demand, transformers/labor shortages add premiums, and storage replacements cycle in.

Long-term before breakeven

Rates peak mid-transition (2040–2060) at 2–4x current levels due to overbuild (3–5x capacity), storage churn (every 12–15 years), and land limits forcing pricey offshore wind. Only after 60–100 years might wholesale drops emerge, but retail lags indefinitely amid endless retrofits.

Household impact

Period Avg. Monthly Bill Rise Annual Extra (600 kWh/mo)

2026–2030 +20–50%	\$300–\$1,200
2030–2040 +50–100%	\$1,200–\$3,000
2040–2060 +100–150%	\$2,500–\$5,000

These hikes compound inflation (experts predict 18%+ through 2030), hitting upstate/NYC renters hardest before any Australia-style relief materializes decades later.

16 - Are NY State residents likely to tolerate the 50% - 150% rate increase?

No, NY State residents are unlikely to tolerate 50–150% electricity rate increases long-term, as current backlash to even 20–30% hikes signals widespread frustration, financial distress, and political pressure that could derail the CLCPA.

Current sentiment

Even modest 2025–2026 increases (e.g., ConEd +11–14%, National Grid +28%) have sparked outrage: 68% of New Yorkers call energy prices "out of control," with 1.3M households (\$1.8B) behind on bills. AARP surveys show seniors skipping meds/food to pay utilities.

Political response

- *Gov. Hochul rejected ConEd hikes, ordered audits, and proposed CLCPA delays to "prevent future increases"—admitting affordability trumps timelines.*
- *PSC approved hikes but faces lawsuits; Republicans blame "green madness"; even Dems push public power fixes.*

Breaking point

Households already pay 58% above U.S. average (27¢/kWh); 50% more = \$3,000–5,000/yr extra by 2040. Polls show 60–70% prioritize affordability over climate goals when costs hit 30–50% hikes. Expect moratoriums, lawsuits, or policy reversals by 2030–35 if trends hold.

17 - What will the rate rebellion in NY State look like?

No, NY State residents are unlikely to tolerate 50–150% electricity rate increases, and a "rate rebellion" is already emerging through protests, lawsuits, and political pushback that could escalate into moratoriums or policy reversals by 2030.

Current rebellion signs

- **Street protests:** *ConEd customers rallied in Union Square (2025), National Grid office in Brooklyn (2026), Ithaca town halls packed against NYSEG's 39% hikes—chants of "no more rate hikes" and calls for public power.*
- **Elected opposition:** *70+ pols (Dems/Repubs) signed letters rejecting ConEd hikes; Hochul ordered audits, rejected increases, and floats CLCPA delays explicitly for affordability.*

Escalation path

- **2030–35:** *If bills hit \$3k–5k extra/yr, expect mass utility shutoffs (1.3M already \$1.8B behind), AARP-led senior marches, small business closures, and PSC lawsuits—mirroring California's 2001 energy crisis revolt.*
- **Voter revolt:** *68% already say prices "out of control"; upstate hardest hit could flip legislatures, forcing cap-and-invest rebates or renewable carve-outs.*

Likely outcomes

Rebellion forces pragmatic delays: partial CLCPA exemptions, nuclear/hydro emphasis, or "public power" takeovers. Full 2040 zero-emission dream dies under \$4k household shocks.

18 - What do Australians think about their renewable energy transition

Australians are broadly in favor of the renewable energy transition, but many want it to be affordable, reliable, and not rushed. Public opinion also shows a clear tension: strong support for clean energy overall, alongside concern about electricity prices, reliability, and local impacts from new infrastructure like transmission lines and wind farms.

What people generally think

*Recent surveys show most Australians support moving away from fossil fuels toward renewables, with 59% to 71% support depending on the poll and question wording. A CSIRO survey found the top priorities were affordability, energy self-reliance, emissions cuts, and reliability, in that order. The same survey found 47% **preferred a moderate-paced transition**, 40% wanted a faster one, and 13% preferred a slower transition.*

Main concerns

The biggest worry is cost. In one national survey, 82% of Australians said affordability was one of their top three energy priorities, and many also worried that the transition could raise household bills. Reliability is another major concern, especially around whether the grid can keep power steady as coal exits. There is also resistance in some communities to local infrastructure, especially transmission lines, even when people support renewables in principle.

Local acceptance

Australians tend to be more comfortable with renewables when projects are not too close to home and when they see a clear benefit. CSIRO found more than 80% would at least tolerate living within 10 km of renewable energy infrastructure, and solar farms were the most accepted type. A 2025 survey found 61% would accept closer facilities if offered electricity discounts. Regional and rural communities can be more skeptical, especially where new projects affect land use or landscapes.

Overall picture

The simplest summary is: Australians largely want the transition to happen, but they want it done well. They are supportive of renewables as a direction, yet they are cautious about costs, speed, and who bears the burden of the change.

Follow-ups

Do opinions vary by age group or generation on energy transition

Yes. In Australia, younger people are generally more supportive of a faster renewable energy transition, while older people are more likely to be cautious, skeptical, or unconvinced that a full transition is necessary.

Age pattern

A 2023 Australian consumer survey found statistically significant differences between the youngest and oldest respondents on how quickly Australia should move to 100% renewables. Younger households were more likely to support a fast transition, including a 2030 target, while older and retired households were less likely to back that pace. The same survey noted that the share of people who think a transition is impossible, or unnecessary, rises with age.

What changes with age

*The gap is mostly about **speed and confidence**, not whether renewables are a good idea at all. Younger Australians tend to be more optimistic and more willing to push for rapid change, while older Australians place more weight on cost, reliability, and practicality. That means support is not simply “young people yes, old people no”; it is more nuanced than that.*

How strong is the divide

The divide is real, but it is not absolute. Even among older Australians, there are many supporters of renewables, and the survey explicitly says these are statistical generalizations rather than fixed views of every person in each age group. Still, the direction of the gap is clear: younger Australians are the most pro-transition, and older Australians are more likely to hesitate.

Broader context

This age pattern matches what has been seen in other countries too, where younger generations are typically more supportive of clean energy and fossil-fuel phaseouts. In Australia, though, the biggest issue across age groups is still not abstract climate belief; it is whether the transition feels affordable, reliable, and fair.

Follow-ups

How do regional differences affect Australian views on renewables

*Regional differences matter mostly because people in regional and rural areas are more likely to feel the **direct** effects of renewables than city dwellers. Nationally, support is still broad, but regional Australians are more likely to worry about where projects are built, how consultation is handled, and whether local communities actually benefit.*

City vs region

The basic pattern is not “cities love renewables and regions hate them.” Surveys show broad support in both places, with regional Australians often supporting renewable energy at roughly two-thirds levels, similar to city Australians. The difference is that support becomes more conditional in regional areas when projects are proposed in people’s own local area.

What regional people care about

Regional Australians tend to focus on land use, property impacts, transmission lines, and whether consultation feels genuine. That is why some communities can support the energy transition in principle while still opposing a specific wind farm, solar farm, or transmission corridor nearby. The issue is often local disruption, not rejection of renewables as an idea.

Support with conditions

*Research cited in regional Australia found that many people back renewables when they see local economic gains such as jobs, cheaper power, or community benefits. Some surveys also found that support rises when projects are paired with concrete benefits like discounts or local investment. In other words, regional support tends to be more **pragmatic** than ideological.*

Misperceptions and backlash

A big theme in the research is that people often overestimate how opposed regional Australians are to renewables. That perception gap can make the debate seem more hostile than it really is. At the same time, rapid rollout and poor engagement have created real backlash in some communities, especially where people feel decisions are being imposed from above.

Overall

*So regional differences mainly change the **terms** of support, not whether support exists. Urban and regional Australians both tend to back the transition, but regional communities are more likely to ask: “Who benefits, who pays, and how will this affect our area?”*

How have Australian energy costs been impacted by the renewable energy transition

Australian energy costs have had a mixed experience during the renewable transition. Wholesale electricity prices fell sharply in 2025 as renewables and storage supplied a growing share of the grid, but households have not yet fully felt those savings because retail bills lag wholesale market changes.

What has happened

By 2025, Australia’s wholesale electricity prices reached their lowest level in four years, and several major markets saw double-digit annual declines. Reuters reported that prices in New South Wales, Queensland, Victoria, and South Australia all fell in 2025, with Queensland and New South Wales posting especially large drops. Other reporting noted that renewables and storage supplied more than half of electricity demand in the National Electricity Market for the first time in late 2025, which helped push wholesale prices down.

Why bills did not fall faster

Household bills do not move in lockstep with wholesale prices, because retailers lock in contracts and pass through costs with a delay. Australia also spent years dealing with energy inflation, coal outages, gas price pressure, and network costs, so retail prices remained elevated even as wholesale prices improved. That means many households are still paying for the earlier price shock rather than the newest market conditions.

Longer-term outlook

The longer-term outlook is more favorable if the buildout continues. The AEMC projects residential electricity prices could fall by 5% to 2030 as new renewables are built, then rise later if deployment slows and demand keeps growing. The Clean Energy Council also argues that delaying the transition would leave households paying more, while faster renewable buildout would keep pressure on prices downward over time.

Net effect

*So the renewable transition has already helped lower **wholesale** electricity costs, but the benefit to households has been delayed and partially offset by other factors. In plain terms: the transition is starting to reduce the underlying cost of electricity, but retail bills are only gradually catching up.*

When did Australia start their renewable energy transition and what are energy prices now relative to when they started

*Australia's renewable energy transition is usually dated from the **mid-2000s to early 2010s**, when federal policy started actively pushing large-scale renewables and states began expanding solar and wind. A key national milestone was the expanded Renewable Energy Target passed in 2009, and Australia's grid is still in the middle of the transition rather than finished.*

*On prices, the clearest comparison is this: **wholesale electricity prices are now generally lower than during the 2022–2023 crisis period, but still above pre-crisis and early-transition levels.** In 2025, wholesale prices fell to a four-year low, with New South Wales averaging just under A\$109/MWh versus nearly A\$125/MWh in 2024, while ABC reporting noted prices are still nowhere near the old A\$40/MWh range.*

So the short answer is:

- **Transition start:** broadly mid-2000s/early-2010s, with 2009 a major policy turning point.
- **Prices now:** lower than the recent spike years, but still materially higher than the low-price era before the energy shock.

If you want, I can also lay this out as a simple timeline from the 2000s to 2026.

What is Australia's per capita heating load relative to NY State

Australia's per capita heating load is generally much lower than New York State's, because Australia has a much milder climate and far less space-heating demand overall. In practical

terms, New York State needs roughly several times more heating energy per person than Australia, with the gap driven mainly by colder winters and longer heating seasons.

What drives the gap

Heating demand is strongly climate-driven, so the colder the region, the higher the per-capita load. New York State also has a large share of detached homes and older building stock that require more heating energy than the typical Australian dwelling. Australia, by contrast, has a warmer climate overall, and in many areas heating is a seasonal need rather than a dominant year-round energy use.

How to interpret it

If you are comparing total household energy use, the difference is not just about heating. New York's per-capita energy use is lower than the U.S. average but still substantially higher than Australia's because heating is a bigger part of the demand mix. So the cleanest takeaway is: Australia's per-capita heating load is much lower than NY State's, likely by a multiple rather than a small percentage.

Important caveat

Exact apples-to-apples numbers depend on whether you mean space heating only, household final energy, or primary energy, and on whether you compare the whole state of New York or NYC specifically. The relationship is clear even without a single perfect figure: New York State has much higher heating demand per person than Australia because of climate and building factors.

19 - What is the multiple of the per capita heating load between All of Australia and all of NY State?

A good ballpark is that New York State's per-capita heating load is about **4x to 6x** Australia's, with **around 5x** being the most reasonable single-number estimate. That's because Australia's climate is much milder, so heating is a smaller share of household energy use, while New York has long, cold winters and much higher space-heating demand.

If you want, I can also turn that into a rough Australia-vs-New York comparison in kWh per person per year.

20 - What is the multiple of the per capita heating load between All of Australia and all of NY State and what are the per capita KWh per year

Using the figures available, the best estimate is that New York State's per-capita heating load is about **5x** Australia's. In annual energy terms, a reasonable rough range is:

- **Australia:** about 1,000 to 1,500 kWh per person per year for space heating.
- **New York State:** about 5,000 to 7,500 kWh per person per year for space heating.

That gives a ratio of roughly **4x to 6x**, centered around **5x**.

How that estimate is built

Australia's climate means heating is a much smaller part of household energy use, while New York's colder winters drive much higher space-heating demand. One source notes Australian household annual consumption can be around 4,615 to 8,619 kWh depending on climate zone, but that is total household electricity, not heating alone. Another source gives New York's annual per-capita energy use and electricity sales, which are much higher in a colder-climate context.

Important caveat

*There is no single clean public figure in the sources for "space-heating kWh per person" for all of Australia and all of New York State, so this is an informed estimate rather than an exact measurement. If you want the most defensible comparison, I'd frame it as: **Australia's per-capita heating load is about one-fifth of New York State's, give or take.***

21 - What is the solar capacity factor in Australia relative to NY State

Australia's solar capacity factor is significantly higher than New York State's, typically around 2x to 2.5x greater. Australia averages 22-28%, while NY State averages 12-17%.

Key figures

- **Australia:** National solar capacity factors generally range from 22% (rooftop/utility mix) to 28% in sunnier regions like Queensland or South Australia.
- **New York State:** Recent data shows 16.8% average in 2023, with utility-scale projects between 14.9% and 21.7%; NYISO planning assumes around 15%.

Why the difference

Australia's abundant sunshine (higher global horizontal irradiance) and latitude give solar panels much more consistent output, while NY's cloudier skies, snow cover, and northern location limit generation to roughly half the annual utilization. This gap means Australian solar produces more electricity per installed kW than NY solar.

22 - What is the area of Australia relative to NY State

*Australia is vastly larger than New York State, with a total land area about **54 times greater**. Australia covers 7,688,287 km², while New York State covers 141,300 km².*

Direct comparison

- **Australia:** 7,688,287 km² (sixth-largest country globally).
- **New York State:** 141,300 km² (27th-largest U.S. state).

- **Ratio:** $7,688,287 \div 141,300 \approx 54.4x$ (land area only; Australia's total area including islands is similar).

This scale difference underscores why Australia's vast sunny interior supports high solar capacity factors, unlike denser, cloudier New York.

23 – What is the population of Australia relative to NY State

*Australia has a larger population than New York State by about **1.4x**. Recent estimates put Australia at roughly 27.7 million people (as of late 2025), while New York State is around 20 million.*

Direct figures

- **Australia:** 27,724,744 (September 2025).
- **New York State:** ~20 million (2025 estimates, down slightly from 20.2 million in 2020).
- **Ratio:** $27.7M \div 20M \approx 1.39x$.

This means Australia has more people spread across vastly more land (54x NY's area), giving it much lower population density.

What is the population density of Australia relative to NY State.

*Australia has a much lower population density than New York State, by a factor of about **40x to 50x**. Australia averages around 3.4 people per km², while New York State averages 160-430 people per km².*

Direct figures

- **Australia:** 3.4 people/km² (using ~27.7 million people over 7.69 million km²).
- **New York State:** 165/km² (or 428/sq mi, using ~20 million people over 141,300 km²).
- **Ratio:** $\sim 3.4 \div 165 \approx 1/48th$ (NY is ~48x denser).

Why it differs

Australia's vast desert interior leaves most people clustered in coastal cities, while New York's density is boosted by NYC and its suburbs. This ties back to earlier points on land area (Australia 54x larger) and population (similar totals).

What are the energy costs in Europe relative to Germany

In Europe, household electricity and gas prices are generally lower than in Germany, which ranks among the most expensive countries on the continent.

Electricity prices vs Germany

- *In the first half of 2025, the average electricity price across 38 European countries was about €28.7 per 100 kWh, while Germany paid around €38.4 per 100 kWh, roughly 37% above the EU average for households.*
- *Several Western European countries such as Belgium, Denmark, Ireland, Italy, Spain, and the Czech Republic have prices close to Germany but still somewhat lower, while many Eastern and Southern EU states (for example Hungary, Bulgaria, Malta) pay well below the German level.*

Gas and broader energy costs

- *For gas, Germany's household prices are also above the EU average, though different procurement strategies, taxes, and weather-driven demand mean some countries (notably several in Southern and Eastern Europe) enjoy markedly lower gas bills than Germany.*
- *When viewed across the wider "Europe-38" group (EU, EFTA, and candidate countries), Germany sits in the top tier of energy-cost countries, whereas Turkey and several Western Balkan states have electricity prices well below Germany, often under €10 per 100 kWh.*

If you specify a particular country (e.g., "costs in France relative to Germany"), I can give a more precise side-by-side comparison.

What are the energy costs in France relative to Germany

Household electricity and wholesale-level energy costs are generally lower in France than in Germany, though the gap can fluctuate depending on the year and market conditions.

Electricity prices (households)

- *Recent data show that German household electricity prices are somewhat higher than in France, with Germany often near the top of the EU price ranking while France sits closer to the middle or slightly below the EU average.*
- *Analyses of 2020–2023 pricing indicate that end-user electricity bills in France have been lower than in Germany, especially for typical residential consumers, partly because France relies more on state-managed nuclear power and has a more regulated tariff structure.*

Wholesale and short-term market

- *In wholesale markets, France's electricity prices have at times traded at a small fraction of German levels; for example, in early 2026 German forward power prices for some months reached about four times the level seen in France, reflecting Germany's greater dependence on gas-linked generation and higher volatility.*
- *This gap is driven by France's heavy use of low-marginal-cost nuclear and renewables versus Germany's phased-out nuclear fleet and stronger dependence on gas, coal, and imported power, which pushes its wholesale and regulated prices up.*

If you tell me whether you mean “energy costs” for households, industry, or gas specifically, I can refine the comparison further.

Follow-ups

How have Australia's utility rates been impacted by their Green Energy Transition

*Australia’s green energy transition has had a mixed but increasingly **downward** effect on electricity prices: wholesale prices have fallen as solar, wind, and batteries expanded, but household bills have often lagged because retail prices reflect networks, fuel shocks, and other costs. In 2025, Australia’s wholesale electricity prices hit a four-year low, and Reuters reported that consumers had still not fully felt those reductions yet.*

What has happened to bills

- *Australians saw very large price spikes in 2022, with average electricity prices rising more than 200% that year and remaining about 60% above 2020–2021 levels on average afterward.*
- *The clean-energy push is expected to lower costs over time because renewables reduce reliance on coal and gas, which are more exposed to fuel price shocks.*
- *A delay in the transition would likely make bills higher, not lower; one report said household bills could be 30% higher in 2030 if renewable buildout stalled.*

Why the effect is uneven

- *Wholesale electricity prices can fall quickly when renewable output is high, but retail bills adjust more slowly.*
- *Grid upgrades, storage, and market design changes add costs in the short run, even as they help stabilize the system later.*
- *Public concern remains high: Australians increasingly worry the transition may affect affordability and reliability, even though support for renewables is still strong.*

Net effect

*The best summary is that Australia’s green transition is **helping reduce underlying power-market costs**, but most households have not yet seen a full pass-through into lower bills. Over time, the transition should be more likely to **stabilize or reduce** utility rates than to raise them, especially if renewable and storage buildout continues.*

APPENDIX E

At what price point does Marcellus and Bakken Shale Gas Drilling increase historically?

AI RESPONSE FOLLOWS

Marcellus Shale Gas — Drilling Activity Price Thresholds

Breakeven (survival floor)

The Marcellus has the lowest breakeven cost of any major U.S. gas play. Tier 1 acreage in northeast Pennsylvania (EQT, Expand Energy, Coterra) breaks even below \$2.00/MMBtu, compared to \$3.50+/MMBtu for Haynesville. This is why Marcellus rigs fell only 37% during the 2022–2024 price crash while Haynesville fell 55% — some Marcellus production remains economic even at depressed prices.

Where drilling actually increases

Historical rig count data points to three distinct price thresholds:

<i>Price Level</i>	<i>Observed Behavior</i>
<i>Below ~\$2.00/MMBtu</i>	<i>Rigs drop sharply; DUC inventory builds; maintenance-mode only</i>
<i>\$2.50–\$3.00/MMBtu</i>	<i>Flat/stabilizing; producers hold position, limited new spuds</i>
<i>~\$3.00/MMBtu</i>	<i>Drilling acceleration begins — this is the empirically confirmed trigger</i>
<i>\$3.50–\$4.00/MMBtu</i>	<i>Sustained growth mode; multiple operators add rigs simultaneously</i>
<i>Above \$4.00/MMBtu</i>	<i>Full-cycle expansion; takeaway constraints become the binding limit, not price</i>

The most direct data point: when Henry Hub recovered above \$3/MMBtu in early 2025, northeast PA rig counts doubled from 5 to 10 within a few months, with Coterra, Repsol, Range Resources, and Infinity Natural Resources all adding rigs simultaneously. The EIA also forecasts that \$4.02/MMBtu Henry Hub in 2026 will "encourage gas-directed drilling" and lift Appalachian output.

The original Marcellus drilling boom (2008–2012) was initiated when prices reached \$8–\$10/MMBtu, but that era pre-dates modern horizontal completions. The relevant modern threshold is \$3.00+ for incremental activity and \$3.50–\$4.00 for meaningful volume growth.

Important caveat — efficiency decoupling: Since 2022, rig counts have fallen ~37% while Marcellus production actually grew 4% due to longer laterals and better completions. A price-driven drilling surge now produces more volume per rig than at any prior point in the play's history. The binding constraint above \$4/MMBtu is increasingly pipeline takeaway capacity, not economics.

Bakken Shale — Drilling Activity Price Thresholds

The Bakken is primarily an oil play where gas is associated/byproduct, so the relevant price signal is WTI crude, not Henry Hub.

Breakeven range

BloombergNEF puts Bakken well breakevens at ~\$58/bbl WTI for a modest return, but this varies sharply by acreage tier:

Tier WTI Breakeven

Top quintile wells ~\$41–\$53/bbl

Mid-tier wells ~\$58–\$65/bbl

Bottom quintile wells ~\$64–\$75/bbl

Breakeven prices have risen roughly 65% since 2020 due to well-quality degradation as premium acreage is exhausted and drilling costs have climbed.

Historical inflection points

Price Level Observed Behavior

*Below Near-complete halt; Continental Resources stopped all drilling in early 2026 at
~\$50/bbl ~\$59/bbl approaching this level*

\$55–\$60/bbl Survival mode; rigs run minimum to hold acreage

\$60–\$65/bbl Marginal recovery; operators begin incremental additions

\$65–\$70/bbl Sustained drilling growth; multiple operators re-enter

\$70–\$80/bbl Robust activity; current rig count of ~22 rigs holds at this level

*Above Pre-pandemic-style expansion, though rig counts still far below the 218-rig
\$80/bbl peak of 2012*

Key historical data: new Bakken horizontal wells fell from 2,273 in 2014 to 738 in 2016 when WTI crashed from ~\$95 to ~\$30. Drilling didn't meaningfully recover until WTI stabilized

above \$50–55. In 2026, despite WTI near \$90, the Bakken rig count sits at only 22 vs. 218 at peak — reflecting both the shift of capital to the Permian and the play's declining well productivity.

Relevance to Your LI LCOE Model

The current LI delivered gas price assumption is \$4.50/MMBtu (HH \$3.52 + \$0.98 Zone 6 basis). At that level, Marcellus is solidly in growth-drilling mode — the \$3.00 inflection has already been crossed. For supply-side price response to be a binding constraint on your 2× and 3× gas scenarios (\$9.00 and \$13.50 LI delivered), you'd need HH to reach roughly \$8–\$12.50/MMBtu. At those levels, the Marcellus would be drilling at full capacity, but takeaway constraints (pipeline into Zone 6/New England) would likely cap incremental supply into the NY/LI market even if wellhead production surged — meaning basis differentials could widen substantially, partially muting the HH signal at the wellhead.

APPENDIX F – SOURCE OF CLCPA PREJUDICE

The following slide was copied from a presentation of Professor Robert Howarth of Cornell University. He sat on the Climate Action Council (CAC) that designed the CLCPA. The prejudices evident in the CLCPA were inherited from this document despite the contradictory evidence shown in Appendices A and B of this document.

This document dates to 2013 and they were predicting that a full transition could be achieved in seven to seventeen years in NY State. Australia, with a superior climate, superior renewable profile, 54 times the area, less expensive land, and lower costs in general, hasn't achieved anything close to this in 20 years while having 25% of the heating load. This thinking infected the Climate Action Council and is a major part of the problem that has led to NY State's current predicament.

Some commonly asked questions:

How long will the transition take? The plan calls for all new electricity generation to come from wind, water, and sun by 2020, leading to 80-85% conversion by 2030 and all fossil-fuel use fully phased out by 2050.

Is there any precedent for such a rapid technological transition? Yes, many. For example, cars replaced horse-drawn carriages as the major means of transportation in the US in just 10 to 20 years between 1910 and 1930.

Are the necessary technologies available now? Yes, the plan relies only on presently available technologies already in commercial use. Engineers have made amazing progress over the past decade, and with support and investment will continue to do so. The time is ripe for moving quickly to renewables.

Won't the transition be expensive? No, many forms of renewable energy are already cost effective compared to fossil fuels (even without considering the external costs to health and global warming), and will only become more so in the future.

What happens when the winds are calm, or at night? The plan calls for storing energy in a variety of ways, and for connecting wind turbines across a large area. (with diverse wind patterns). There is no need for base-load production from coal.

Can't shale gas serve as a bridge fuel, until renewables can be fully deployed? Shale gas is disastrous in terms of global warming, competes with renewables in terms of scarce capital for energy investment, requires large-scale industrialization of the landscape, and simply is not needed.

Does the plan call for nuclear energy? No. Unsolved issues of waste disposal and other dangerous risks make nuclear an unacceptable option, and renewable energy is less expensive.

Don't wind turbines kill birds? Pollution from coal and natural gas kill more than 10 times as many birds as wind turbines, per kilowatt of electricity produced.

The 2030 plan: The time is NOW!

The 2030 Plan for a fossil-fuel free New York

Contents lists available at SciVerse ScienceDirect

Energy Policy

Journal homepage: www.elsevier.com/locate/enpol

Examining the feasibility of converting New York State's all-purpose energy infrastructure to one using wind, water, and sunlight

Mark Z. Jacobson^{a,*}, Robert W. Howarth^b, Mark A. Delucchi^c, Stan R. Scobie^d, Jannette M. Barth^e, Michael J. Dvorak^f, Megan Klevze^g, Hind Katkhuda^h, Brian Mirandaⁱ, Navid A. Chowdhury^j, Rick Jones^k, Larson Plano^l, Anthony R. Ingraffea^m

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In March 2013, a team of scientists and engineers from Stanford, Cornell, and other institutions published a peer-reviewed study calling for an aggressive transition to make New York State completely free of fossil fuels. All energy for electricity generation, transportation, heating, and industry, would come from the wind, water, and sun.

The plan uses only presently available technologies already in commercial use. This cost-effective plan saves lives, reduces global warming, and increases the energy security and competitiveness of New York.



Cornell University

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STANFORD
UNIVERSITY



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APPENDIX G - AUSTRALIAN RENEWABLE SPENDING AND INSTALLED RENEWABLE CAPACITY

How much money has Australia spent on their renewable energy transition in both Australian dollar and US Dollars

There is no single official “total spend so far” number for Australia’s renewable energy transition, but available government and analyst estimates point to hundreds of billions of Australian dollars in cumulative and committed spending, with total required investment to reach net zero by 2050 in the trillions.

What we can say with evidence

1. Government clean-energy transition commitments so far

*Several federal programs and budget measures quantify **direct public commitments** to the transition (generation, grids, storage, industrial policy), but they cover only part of overall spending (they exclude most private investment and many state programs).*

Key federal figures:

- Around 23 billion AUD committed by the federal government “towards transforming Australia’s energy system” (modernising infrastructure, accelerating investment in renewable generation and storage, efficiency, and electrification), according to an official budget factsheet.*
- Within that, the **Rewiring the Nation** program provides up to 20 billion AUD in low-cost finance for transmission needed for renewables integration.*
- The 2023–24 federal budget added about 4 billion AUD in new energy-transition investments (about 2.7 billion USD at the time).*
- The 2024–25 budget and “Future Made in Australia” package committed **22.7 billion AUD over the next decade** to support industrial and renewable-energy development and position Australia as a “renewable energy superpower.”*

If you add just the clearly stated headline federal packages above (not double-counting overlapping items), you get on the order of:

- Roughly 45–50 billion AUD of major federal transition-related commitments over the early-2020s period and coming decade (23 billion AUD clean-energy transformation + 22.7 billion AUD “Future Made in Australia”), plus additional, smaller items.*

Using an approximate recent exchange rate of 1 AUD ≈ 0.65 USD, this is about:

- 45–50 billion AUD ≈ 29–33 billion USD.*

*These numbers are **federal commitments**, not total national spending.*

2. Federal funding bodies and subsidies

Additional federal spending channels add billions more of public money:

- *The Australian Renewable Energy Agency (ARENA) has committed about **2.25 billion AUD** to 663 projects since 2012.*
- *The Clean Energy Finance Corporation (CEFC) has provided **13.7 billion AUD** in debt and equity funding (public capital that leverages much larger private co-investment).*
- *One assessment cites about **29 billion AUD in federal subsidies for renewables over the past decade** (this aggregates different support mechanisms).*

Those three figures alone sum to roughly:

- *Around 45 billion AUD of federal support and financing over roughly the last decade (2.25 + 13.7 + about 29), or about 29 billion USD.*

*Again, this is a subset of total public and private spending but shows the **scale**.*

3. Total investment required vs. already spent

*Most comprehensive numbers you'll see are **forward-looking estimates** of how much Australia must invest to reach net-zero; they can give you an order-of-magnitude sense of the transition's financial scale:*

- *The Australian Industry Energy Transitions Initiative estimates **about 625 billion AUD of capital expenditure by 2050** to decarbonise industry and the energy system, averaging about 21 billion AUD per year to 2050.*
- *BloombergNEF estimates roughly **3 trillion AUD (about 1.9 trillion USD)** in total investment is required to meet Australia's 2050 net-zero target, averaging about 104 billion AUD per year.*
- *A separate analysis similarly states that Australia's push to net zero by 2050 will require around **3 trillion AUD of investment**, or roughly 100 billion AUD a year.*

Using 1 AUD \approx 0.65 USD:

- *625 billion AUD \approx about 406 billion USD.*
- *3 trillion AUD \approx about 1.95 trillion USD.*

*These figures are **required/expected investment**, not what has already been spent.*

4. Why there is no single "has spent" figure

A precise total "how much has Australia spent to date on the renewable energy transition" is not published as one consolidated number because:

- Spending is split across federal and state governments, public finance institutions, private project developers, households (rooftop solar, batteries), and industry, and is often reported separately.
- Many reports focus on **annual investment flows** or **required future capital** rather than constructing a historical cumulative series back to the start of the transition.
- Some large figures you see (like 3 trillion AUD) refer to **all economy-wide net-zero investment**, not just electricity or strictly “renewables” in the power sector.

Because of this, any single number saying “Australia has spent X so far” would be an estimate that depends heavily on methodology and inclusions (e.g., does it count electric vehicles, transmission, hydrogen, industrial decarbonisation, or only power-sector renewables?).

5. Practical ballpark answer

Based on available evidence:

- Direct, headline **federal** renewable-transition-related commitments and support over roughly the last decade are at least on the order of **tens of billions of AUD** (easily 40–80 billion AUD when you combine budget packages, subsidies, and public-finance programs such as CEFC and ARENA, with some uncertainty and potential overlap).
- Including state programs and private capital for large-scale wind, solar, storage, and rooftop solar, total **national** spending to date will be **much higher**, but robust published estimates of the cumulative total are not readily available; most rigorous work instead gives forward-looking totals of **hundreds of billions to several trillion AUD** required by 2050.

If you want, I can narrow this down to a specific segment (for example, “federal government spending to date on electricity decarbonisation only” or “annual total investment in renewables in Australia over the last 10 years”) and work up a more precise number series.

How many GW of solar does Australia have installed

Australia has about **40 GW** of total installed solar capacity as of the end of 2024, combining roughly 26.1 GW of distributed solar and 13.4 GW of centralized solar.

If you mean **rooftop solar only**, the total was **28.3 GW** by the end of 2025.

How many GW of Wind does Australia have installed

Australia has about **13.3 GW** of installed wind capacity as of September 2024. Another source gives a broader installed wind capacity figure of **15,382 MW** (about **15.4 GW**), depending on the reporting date and definition used.

If you want, I can also give you the latest combined **solar + wind** installed capacity for Australia.

How many GW of Hydro does Australia have installed

*Australia has about **6–7 GW of installed hydro capacity** if you mean **conventional hydroelectric generation**; one source notes hydro made up about 8% of Australia's total installed power generation capacity in 2023, and another says hydroelectricity has supplied around 5–7% of Australia's electricity for decades.*

*If you include **pumped hydro storage**, the number is higher, but that is usually reported separately from hydro generation*

*Here are approximate recent totals for **wind + solar + hydro generation** in both Australia and New York.*

Australia (recent-year totals)

*A 2023–24 Australian energy-account report shows that **wind, solar, and hydro together supplied about 34% of domestic electricity**, with:*

- ***Wind**: about 112 PJ → roughly 31,000 GWh*
- ***Solar**: about 175 PJ → roughly 48,600 GWh*
- ***Hydro**: smaller share and slightly down year-on-year, on the order of 15,000–16,500 GWh in recent system-wide tables.*

Adding these together gives a ballpark:

- ***Australia (wind + solar + hydro) ≈ 95,000–100,000 GWh per year recently.***

TOTAL RENEWABLES 95,600

83% SOLAR AND WIND

New York (recent-year totals)

*For New York, the best-available compilation is for **2022 renewable electricity generation**:*

- ***Hydro**: about 27,000 GWh (majority of renewables).*
- ***Wind**: about 4,800 GWh (roughly 13% of renewables).*
- ***Solar**: about 4,700 GWh (also roughly 13% of renewables).*

Adding those:

- ***New York (wind + solar + hydro) ≈ 36,500 GWh per year in 2022***

From the NYISO 2025 Gold Book Page 104 and pp 41

2024 Values

Hydro – 27935 GWh

Solar - 503 GWh

BTM Solar 8,071

Off Shore Wind 191 GWh

Land Based Wind - 5,821 GWh

TOTAL NY STATE RENEWABLES - 42,521 GWh

TOTAL WIND AND SOLAR 14,586 GWh

% HYDRO 66%

Table III-3c: Annual Net Energy Generation by Zone and Type – 2024

Generator Type	ZONE											TOTAL	
	A	B	C	D	E	F	G	H	I	J	K		
Annual Net Energy Production (GWh) ⁽²⁾													
Fossil	Steam Turbine (Oil)	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.0
	Steam Turbine (Oil & Gas)	5.2	3.3	12.6	0.0	0.0	0.0	1,526.7	0.0	0.0	2,235.9	5,027.7	8,811.4
	Steam Turbine (Gas)	0.0	0.0	172.6	0.0	0.0	0.0	14.7	0.0	0.0	1,277.1	0.0	1,464.4
	Combined Cycle (Oil & Gas)	309.1	0.0	216.3	12.2	11.2	13,053.2	5,001.9	0.0	0.0	22,691.4	2,605.7	43,901.0
	Combined Cycle (Gas)	0.0	18.9	6,183.0	175.2	3.7	0.0	4,158.1	0.0	0.0	0.0	262.4	10,801.3
	Jet Engine (Oil)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55.0	55.0
	Jet Engine (Oil & Gas)	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	590.5	124.5	715.8
	Jet Engine (Gas)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	42.5	42.5
	Combustion Turbine (Oil)	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0	11.2	11.7
	Combustion Turbine (Oil & Gas)	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	51.5	610.5	662.4
	Combustion Turbine (Gas)	28.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	591.2	185.5	805.0
	Internal Combustion (Oil)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	1.8
	Internal Combustion (Oil & Gas)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Internal Combustion (Gas)	0.0	0.1	0.0	0.0	1.4	0.0	0.0	0.0	0.0	0.0	0.0	1.5
Nuclear	Steam (PWR Nuclear)	0.0	4,799.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,799.1
	Steam (BWR Nuclear)	0.0	0.0	22,273.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22,273.9
Renewable ⁽¹⁾	Conventional Hydro	15,594.8	24.5	441.9	7,602.2	2,121.6	1,958.6	192.2	0.0	0.0	0.0	0.0	27,935.8
	Internal Combustion (Methane)	53.1	28.0	90.6	47.8	39.0	64.8	0.0	0.0	0.0	0.0	0.0	323.3
	Steam Turbine (Refuse)	261.6	0.0	210.6	0.0	0.0	67.4	0.0	397.7	0.0	0.0	969.7	1,907.0
	Land-Based Wind	958.0	0.0	1,782.8	1,217.2	1,863.4	0.0	0.0	0.0	0.0	0.0	0.0	5,821.4
	Offshore Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	190.9
	Solar	0.0	0.0	63.8	0.0	0.0	346.2	0.0	0.0	0.0	0.0	93.2	503.2
Storage ⁽³⁾	Energy Storage	-7.6	0.0	0.0	-1.2	0.0	-9.2	-0.2	0.0	0.0	0.0	0.0	-18.2
	Pumped Storage Hydro	-238.4	0.0	0.0	0.0	0.0	-152.1	0.0	0.0	0.0	0.0	0.0	-390.5
Totals		16,964.1	4,873.9	31,471.1	9,053.4	4,040.3	15,328.9	10,895.1	397.7	0.0	27,437.6	10,180.6	130,642.7

(1) - The Renewable Category does not necessarily match the New York State Clean Energy Standard (CES) Definition.

(2) - Values are from the 2024 Net Energy column in Table III-2a and Table III-2b.

(3) - The Energy Storage Category includes Battery and Flywheel fuel types.

BEHIND THE METER (BTM) SOLAR (GWh)

Table I-10b: Non-Solar Distributed Generation Annual Energy Reductions, Behind-the-Meter
Reflects Total Cumulative Impacts

Reductions in Annual Energy by Zone - GWh

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2025	98	46	295	12	162	220	75	12	81	769	217	1,987
2026	98	46	301	12	168	231	81	12	87	809	224	2,069
2027	98	46	306	12	173	243	87	12	93	835	232	2,137
2028	98	46	312	12	179	249	93	12	98	861	239	2,199
2029	98	46	318	12	185	254	98	12	104	883	247	2,257
2030	98	46	324	12	191	260	104	12	110	901	254	2,312
2031	98	46	330	12	197	266	110	12	116	920	261	2,368
2032	98	46	335	12	202	272	116	12	121	938	269	2,421
2033	98	46	341	12	208	278	121	12	121	953	276	2,466
2034	98	46	347	12	214	283	127	12	121	968	280	2,508
2035	98	46	353	12	220	289	133	12	121	982	283	2,549
2036	98	46	358	12	225	295	139	12	121	997	287	2,590
2037	98	46	364	12	231	301	145	12	121	1,008	291	2,629
2038	98	46	370	12	231	306	150	12	121	1,019	294	2,659
2039	98	46	370	12	231	312	150	12	121	1,030	298	2,680
2040	98	46	370	12	231	318	150	12	121	1,038	302	2,698
2041	98	46	370	12	231	318	150	12	121	1,045	305	2,708
2042	98	46	370	12	231	318	150	12	121	1,052	309	2,719
2043	98	46	370	12	231	318	150	12	121	1,060	313	2,731
2044	98	46	370	12	231	318	150	12	121	1,067	316	2,741
2045	98	46	370	12	231	318	150	12	121	1,074	320	2,752
2046	98	46	370	12	231	318	150	12	121	1,078	324	2,760
2047	98	46	370	12	231	318	150	12	121	1,082	327	2,767
2048	98	46	370	12	231	318	150	12	121	1,085	331	2,774
2049	98	46	370	12	231	318	150	12	121	1,089	335	2,782
2050	98	46	370	12	231	318	150	12	121	1,093	338	2,789
2051	98	46	370	12	231	318	150	12	121	1,096	342	2,796
2052	98	46	370	12	231	318	150	12	121	1,100	342	2,800
2053	98	46	370	12	231	318	150	12	121	1,104	342	2,804
2054	98	46	370	12	231	318	150	12	121	1,107	342	2,807
2055	98	46	370	12	231	318	150	12	121	1,111	342	2,811

How many GW of solar are currently planned for installation in Australia

*Australia has **no single official “current plan” figure in GW**, but the closest proxy is the **Capacity Investment Scheme (CIS) and project-pipeline ambitions**:*

- *Under the CIS, Australia plans to add **up to 26 GW of new renewable-generation capacity** (mostly wind and solar) and **up to 14 GW of dispatchable capacity**, so **up to 26 GW of new renewable capacity** could be realized if the program is fully deployed.*
- *The total would be **larger than that** if you also count:

 - *The **AEMO-aligned expectation of about 36–37 GW of rooftop solar by 2030**, on top of the roughly 26–27 GW already installed by mid-2025.**

- *Very large “mega-solar” proposals such as **multi-GW projects in the Northern Territory and Western Australia** aimed at powering green-hydrogen or export-linked industry, which add several tens of GW of proposed solar capacity, though many are still in early planning stages.*

Practical takeaway

- ***Planned + pipeline solar capacity** (through schemes like CIS plus state-led projects) is on the order of **tens of GW** beyond what is already installed, with **roughly 26 GW of new renewable capacity** explicitly targeted under CIS, much of it solar.*
- *Because the pipeline is partly speculative and project-by-project, there is **no single “X GW of solar currently planned” number**; the **26 GW CIS-linked renewable-capacity target** is the best-known planning-level anchor.*