INDUSTRIAL DECARBONIZATION SERIES

How India’s Specialty Chemical Plants Can Cut Energy Costs and Scope 1, 2 & 3 Emissions

TOPTIER ENERGY SERVICES PVT LTD · Industrial Decarbonization Series · 21 November 2026



Original AI-generated illustration of a representative specialty chemical batch processing hall.

The costliest energy in a specialty chemical plant can be the steam it buys twice. The first bill comes from heating a batch. The second arrives when usable heat leaves through a cooling system while the next operation heats fresh water. Both utilities may be running exactly as designed. The missed opportunity lies in how the processes are scheduled and connected.

That is where a CFO and a plant head can start the same conversation. Which energy purchases actually support saleable output, and which could the plant avoid without changing product quality or production reliability?

Start with the batch schedule, steam balance and electricity meter. A renewable contract becomes easier to size once the avoidable load is visible.

The hidden energy story behind specialty chemicals

Specialty chemicals are typically sold for what they do in a customer's process or product. An additive can improve the stability of a lubricant or the performance of a material. A formulated ingredient can give a coating, sealant or industrial fluid its required properties. Plants making these products may look similar from the road, but their energy profiles depend heavily on what happens inside the vessels.

A blending plant receives, stores and doses feedstocks, then mixes, filters and packs the finished formulation. It may need tank tracing or feed preheating to manage viscosity. A batch synthesis plant can also need controlled heating and cooling, separation, solvent recovery, drying, scrubbing and more intensive effluent treatment. Dry polymer compounding uses another combination of loads, including extrusion drives, barrel heaters, feeders, cooling and pellet handling. A plant may contain more than one of these operations. Map each separately before comparing sites or extrapolating a benchmark. JRC reference for organic fine chemicals · Indian EIA guidance for synthetic organic chemicals

From raw materials to dispatch

01 Receive and dose	Feedstock tanks and dosing pumps use electricity and, where required, tracing heat.
02 Blend or react	Agitators use electricity. Jackets can require useful steam and chilled water.
03 Finish	Filter, recover solvent or dry as required. Use recovered heat where temperature and timing match.
04 Release and dispatch	Verify product quality, pack and dispatch. Track rework, residue and yield.
Utilities and losses	Gas → boiler → useful steam + stack/distribution losses. Electricity → process and utility equipment.
Emissions pathways	Fuel combustion → Scope 1. Purchased power → Scope 2. Feedstock and freight → Scope 3.

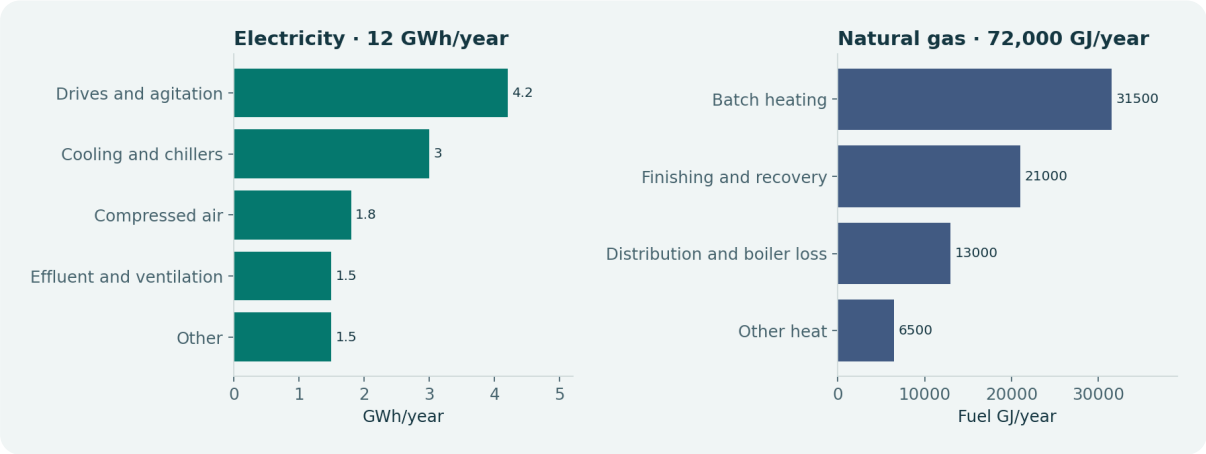
Qualitative process map · JRC organic fine chemicals reference and TOPTIER engineering analysis

Representative batch chemical process and energy pathways.

Start at receipt and follow a representative tonne through storage, dosing, blending or reaction, finishing, quality release and dispatch. Record electricity in kWh, fuel on a consistent net calorific basis in GJ, and useful heat at the process interface where it can be measured. Track rework and rejected batches alongside energy. A product with long cooling and recovery steps can have very different utility demand from a simple blend, even at the same output. Compare runs within product families and account for grade changes, seasonal cooling needs and batch yield before drawing conclusions.

Step	Energy to meter	Common loss to investigate	First action
Storage and transfer	Tank heating, tracing, pumps	Tanks kept hot between campaigns	Validate minimum holding temperature and schedule

Step	Energy to meter	Common loss to investigate	First action
Blending and reaction	Agitators, jackets, steam and chilled water	Utility overlap, idle circulation and partial loads	Log heating, cooling and hold times by recipe
Separation and finishing	Steam, vacuum, cooling and drying	Poor heat integration or unnecessary recovery duty	Review heat balance and quality limits
Compounding where applicable	Extruder drives, heaters, cooling	Idle operation, scrap and unstable throughput	Track kWh per saleable tonne by grade
Utilities and abatement	Boilers, compressors, chillers, ETP loads	Steam leaks, air leaks, poor staging and fouling	Meter distribution and submeter large end uses
Dispatch	Packing lines and warehouse equipment	Idle operation and avoidable rehandling	Link dispatch schedule to equipment runtime

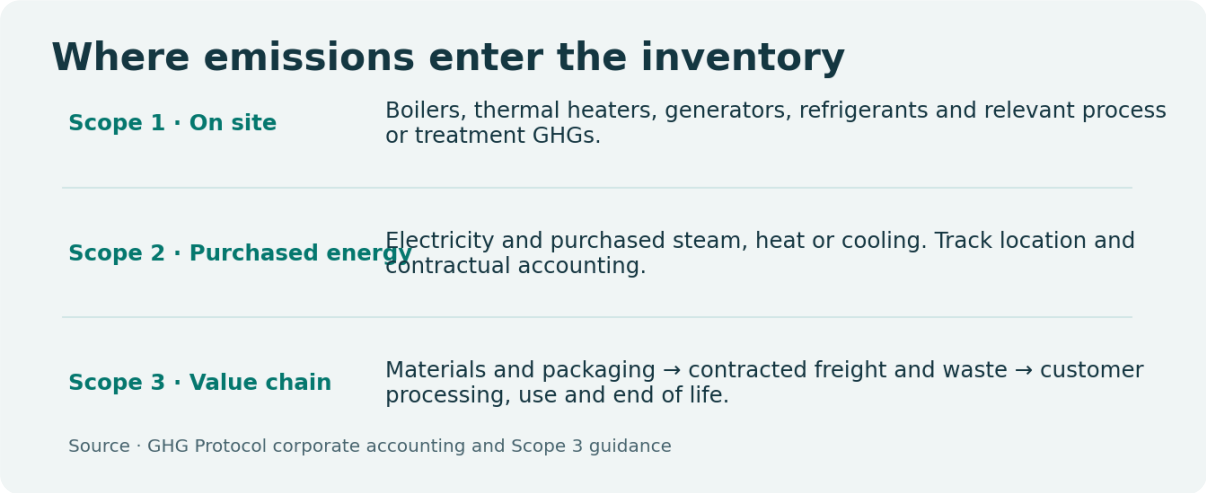


Illustrative allocations for the case plant. Site loads will depend on product mix and process.

A useful first dashboard has four indicators. Track gas GJ per saleable tonne, electrical kWh per saleable tonne, condensate return and peak kVA by tariff window. Compare these with daily production and batch events.

Boiler gas per tonne rising while vessel demand stays steady points to a utility issue. Cooling power rising only on a particular recipe points the team toward that process or its operating sequence. The meter tells you where to look. The operator usually knows what changed.

Where the carbon footprint comes from



Emission sources across the plant and its value chain.

Scope 1 covers direct emissions from controlled sources. Start with boilers, thermal-fluid heaters, standby diesel and owned vehicles. Screen refrigerant leakage, process greenhouse gases and emissions from on-site wastewater treatment where the treatment conditions and effluent composition warrant it. A solvent loss can be material for worker exposure, air permitting, product yield and cost. Classify greenhouse gas emissions using the actual substance and pathway. Use refrigerant top-up, recovery and maintenance records and retain a consistent global warming potential basis.

Scope 2 covers purchased electricity and purchased steam, heat or cooling where present. Location-based accounting uses the grid-average factor

applicable to the consumption location. Market-based accounting follows the relevant contractual instruments and factor hierarchy. For an open-access contract, document who owns the renewable attributes, the reporting market and vintage, and the cancellation or retirement evidence where relevant. Qualifying purchased wind or solar can reduce market-based Scope 2. Grid-delivered volumes remain part of the grid-average calculation in the illustrative model below. Track emissions claims, metered delivery and bill settlement in three linked reconciliations. GHG Protocol Scope 2 Guidance

Scope 3 often begins with feedstocks, packaging and logistics. Screen base fluids, resins, additives, solvents and outsourced services using kilograms purchased, material origin and the best available cradle-to-gate factors. A spend-based estimate can flag priorities. Get supplier-specific data for the largest materials and check system boundaries, allocation, factor year and the treatment of recycled inputs. Product carbon footprints can then inform design choices and customer discussions. Product footprints and company-wide inventories use different boundaries and should be reconciled before the figures enter sales material. GHG Protocol Scope 3 calculation guidance

Scope 3 category	Screening and action
1 Purchased goods and services	Prioritize chemical feedstocks, packaging and toll processing. Procurement can set data requirements with suppliers.
2 Capital goods	Screen reactors, extruders and utility packages in purchase years. Request comparable supplier data.
3 Fuel- and energy-related activities	Use upstream fuel and power factors and relevant transmission losses outside Scope 1 and 2.
4 Upstream transport and distribution	Include inbound freight and purchased distribution. Request tonnage, distance and mode.

Scope 3 category	Screening and action
5 Waste generated in operations	Obtain treatment routes and manifests for spent chemicals, sludge and outsourced disposal.
6 Business travel	Use mode and distance data where material.
7 Employee commuting	Screen shift transport, commuting modes and remote work where relevant.
8 Upstream leased assets	Include relevant leased assets outside the operational inventory boundary.
9 Downstream transport and distribution	Screen customer-paid distribution beyond the reporting company’s purchased freight.
10 Processing of sold products	Check downstream energy and processing of sold intermediates with customers.
11 Use of sold products	Evaluate use-phase pathways by application and distinguish direct and optional indirect use-phase accounting.
12 End-of-life treatment	Estimate treatment for products and relevant packaging sold, using defensible customer-market assumptions.
13 Downstream leased assets	Screen assets owned and leased to third parties outside Scope 1 and 2.
14 Franchises	Screen the organizational structure and document applicability.
15 Investments	Screen holdings and joint ventures outside the consolidated operational boundary.

What conventional operation costs

A plant that keeps boilers, compressors and cooling equipment running for the worst-case batch may get reliable production while paying for spare capacity on ordinary days. A site that has started metering utilities and returning condensate is better positioned to explain its energy cost per tonne. A more advanced site can match clean power procurement to its load, dispatch heat recovery according to batch schedules and ask suppliers for verified material footprints. These are operating profiles. Each site still has to judge the trade-offs against its own product slate and utility contracts.

The commercial risk reaches beyond the electricity bill. A business exposed to gas price spikes may have less room to defend margins on long-duration supply contracts. Customers may also ask for supporting carbon data at product level before supplier selection or annual renewal. An energy plan that connects costs to individual recipes, and raw-material footprints to the bill of materials, helps answer both requests. It also gives management a baseline for verifying promised savings after commissioning.

In India, check the latest notified facility list and applicable intensity targets before assuming that a site is an obligated entity under the Carbon Credit Trading Scheme. BEE identifies petrochemicals and chlor-alkali among the sectors considered for the compliance transition. That sector-level list is a screening input. Listed customers may also request data for BRSR or BRSR Core. SEBI's March 2025 circular made relevant value-chain ESG disclosure voluntary for the top 250 listed entities from FY 2025–26. In the EU, CBAM operates in its definitive phase from 2026 for specified goods. Screen the actual CN code and customer obligations. Separately track voluntary buyer requests and proposed rule changes in the commercial register. For air emissions, effluent and hazardous waste, reconcile retrofit plans against the facility's consent and authorizations with the relevant state pollution

control board. BEE Carbon Market · Notified GHG intensity rules · 2026 notified amendment · SEBI BRSR FAQs · EU CBAM definitive regime

Which technologies deserve a trial?

Conventional equipment and practical upgrades

Once-through steam	Return clean condensate or use indirect feedwater preheating where contamination risk is material.
Fixed utility loads	Use appropriate controls for fans, cooling pumps and compressors. Verify minimum process duty.
Gas-fired hot water	Recover useful heat first. Fit a heat pump where source and sink temperatures align.
Grid-only power	Compare on-site solar and delivered wind or hybrid power on usable interval-matched volume.

Source · TOPTIER engineering analysis, JRC and IEA

Common technology substitutions to screen against process and cost requirements.

Steam and hot water. Survey steam traps and insulation, balance headers and return condensate that meets the boiler-feedwater specification. Where product contamination is possible, consider indirect heat recovery with a separate loop. Plot waste-heat sources and legitimate process sinks by temperature and time. If a sink is intermittent, test a thermal buffer before selecting a larger exchanger. Verify net fuel savings against production and weather after commissioning.

Cooling, compressed air and motor loads. Match chiller sequencing and chilled-water setpoints to process needs. Find unproductive compressor demand by checking off-shift flow and header pressure. Size variable-speed drives against measured torque, minimum flow and actual duty. For

agitated vessels, mixing quality and safety limits govern speed changes. Retain critical-service redundancy through any retrofit.

Electrification. A heat pump can be attractive when a reliable warm source and a compatible hot-water duty operate together. Request a guaranteed performance map at the actual source and delivery temperatures and include pumps and controls in the power calculation. At ₹8.50/kWh and a coefficient of performance of 3, the simplified electricity cost is ₹787 per useful GJ. Gas at ₹1,100 per fuel GJ and 82% boiler efficiency costs ₹1,341 per useful GJ. At these inputs, the heat pump reaches fuel-cost parity near a coefficient of 1.76, before capex, maintenance and demand charges. An electric boiler with near-unity efficiency faces a far higher electricity cost per useful GJ under the same tariff, although cheap surplus power, short-duration duties or resilience can change the use case. IEA industrial electrification of heat and steam

Other thermal options. Assess biomass or biogas only after screening year-round fuel quality, delivered price, ash or residue handling, air consents and lifecycle emissions. Consider hydrogen where there is a process requirement or where firm delivered fuel and verified carbon intensity support the case. Keep existing capacity available through proof of performance when production depends on the utility being replaced.

How to buy renewable power for a batch plant

Renewable supply matched to plant demand

Solar	Rooftop or delivered solar → daylight plant loads.
Wind or hybrid	Delivered wind or hybrid → seasonal, evening and overnight loads where generation supports them.
Grid	Utility supply → residual demand, standby and regulated settlement.
Optional BESS	Residual surplus → storage losses and discharge → remaining peaks or critical loads.

Source · TOPTIER procurement screening framework

Screen each source against the time profile of usable demand.

Run the electricity procurement comparison on the same interval data for every option. Use a year of 15-minute or hourly load, together with buyer-meter generation forecasts or adjusted delivery profiles. Aggregate by the actual time-of-day billing and settlement windows. Test daytime rooftop solar first within structural, interconnection and operating constraints. Compare open-access solar, standalone wind and hybrid offers on delivered cost and usable volume. Wind can serve evening and overnight demand when the site's generation profile supports that pattern. Model seasonal output and a low-generation year before signing a minimum offtake or take-or-pay commitment.

Compare third-party green open access, captive ownership and group captive structures. Captive ownership adds capital, availability and operating exposure. Group captive can share project exposure but requires equity, consumption monitoring and compliance with Rule 3 as amended in March 2026. Use the final notified text and verification procedure for

ownership, captive use, special-purpose vehicles and applicable settlement provisions. The national green open-access framework provides a 100 kW entry threshold for eligible non-captive consumers and exempts captive consumers from that threshold. State and licensee rules govern implementation. In Maharashtra, use the applicable MERC open-access regulations and current MSEDCL or other licensee tariff schedules, including the March 2026 MSEDCL review order where applicable. In Gujarat, start with GERC's Green Energy Open Access Regulations and gazetted amendments, along with the local distribution licensee's tariff and applicable orders. Treat consultation text as a proposal until notified. Review transmission and wheeling charges and losses, cross-subsidy and additional surcharges where applicable, banking, scheduling, deviation and standby costs. Confirm which components the proposed rate includes. Ministry of Power green OA summary · March 2026 captive amendments · MERC open-access rules · GERC renewable regulations register · MSEDCL tariff schedules

A practical battery test starts with residual demand after the solar-wind mix. Suppose 1 MWh of midday energy remains available and an evening window can use all of it. At 85% round-trip efficiency the battery delivers 0.85 MWh. If charging energy has an opportunity cost of ₹3.50/kWh and evening purchases cost ₹10/kWh, the gross spread is ₹5,000 per cycle before degradation, financing, fixed costs and losses outside the battery. Cap the dispatch at actual evening demand. Add demand-charge savings only when the battery can reliably cover the measured interval that sets monthly billed demand. Value backup separately based on critical loads, run time and the transfer capability of the installed system.

What the numbers could look like

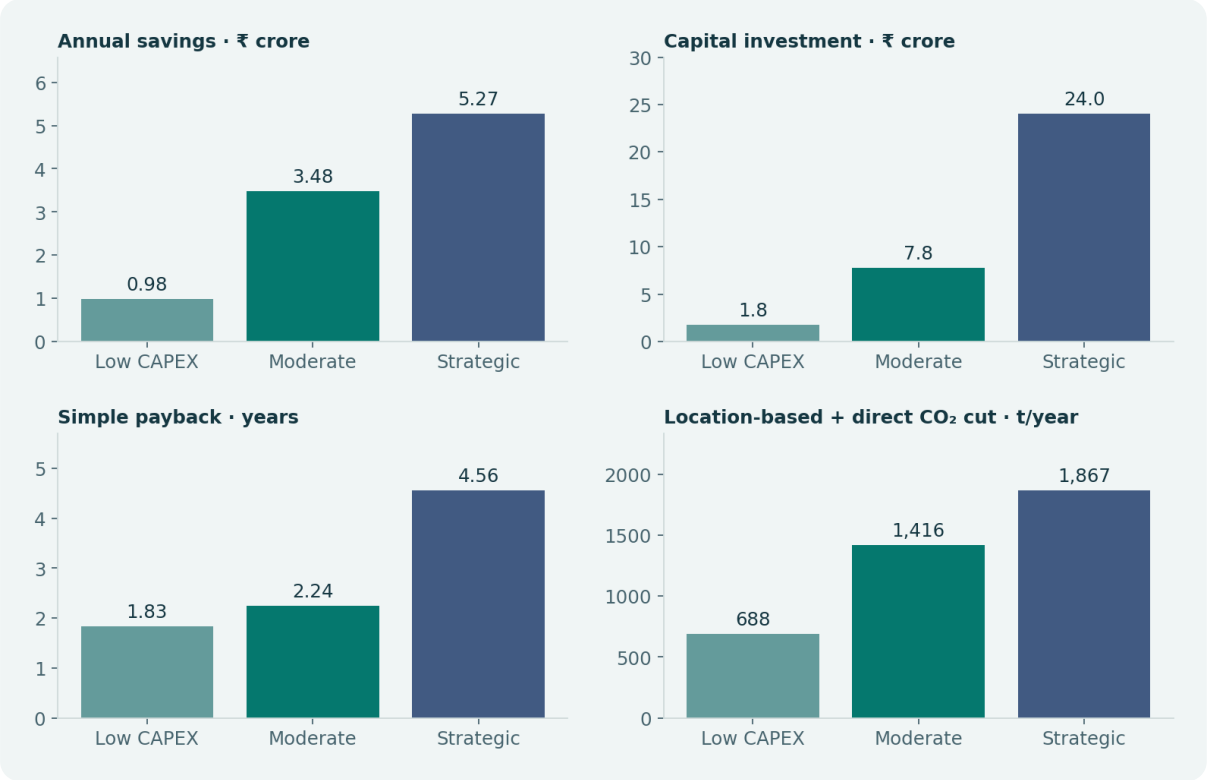
Consider a hypothetical Indian specialty chemical batch plant operating across shifts. It uses 12 GWh of electricity, 72,000 GJ of natural gas a year and has 3 MW of peak real power, equivalent to about 3.16 MVA at a 0.95 power factor. Its annual electric load factor is about 46%. The illustrative load has daytime production peaks and overnight base loads from utilities and ongoing batches. Annual modeled variable energy cost starts at ₹18.12 crore. The assumptions are ₹8.50/kWh avoided variable grid cost, ₹5.80/kWh landed charge on usable open-access power, ₹1,100/GJ of delivered gas, 82% boiler efficiency and ₹200 crore annual revenue. Fixed charges, taxes, working capital, incentives and major equipment replacement are outside the comparison. These inputs are scenario assumptions and should be replaced with actual metered volumes and offers for an investment decision.

Modeled result	Baseline	Low CAPEX	Moderate	Strategic
Electricity consumption (MWh/yr)	12,000	11,280	10,800	11,927
Natural gas (GJ/yr)	72,000	68,400	61,200	39,600
Used open-access volume (MWh/yr)	0	0	5,000	7,000
CAPEX (₹ crore)	0.00	1.80	7.80	24.00
Incremental O&M (₹ crore/yr)	0.000	0.025	0.080	0.250
Net annual savings (₹ crore)	0.00	0.98	3.48	5.27
Simple payback (years)	—	1.83	2.24	4.56
NPV, 10 years at 10% (₹ crore)	—	4.24	13.57	8.36
Pre-tax IRR (%)	—	53.9	43.4	17.6

Modeled result	Baseline	Low CAPEX	Moderate	Strategic
Illustrative operating margin gain (percentage points)	0.00	0.49	1.74	2.63
Fuel CO_2 reduction · Scope 1 (t/yr)	0	202	606	1,818
Electricity CO_2 reduction · Scope 2 location (t/yr)	0	486	810	50
Electricity CO_2 reduction · Scope 2 market proxy (t/yr)	0	486	4,185	4,774
Net abatement cost · Scope 1 + location Scope 2 (₹/t)	—	-10,031	-15,599	-7,286

Cash flow assumes upfront capital and year-end steady cash savings. Abatement cost divides capital less discounted savings by discounted Scope 1 and location-based Scope 2 reductions over the same ten years. A negative result indicates net savings per modeled tonne. Strategic CAPEX covers assumed electrification and heat integration. Supplier engagement is included in the roadmap. Storage is subject to a separate business case and has zero modeled CAPEX or benefit. No Scope 3 reduction is booked without activity and factor data.

Baseline combustion and location-based electricity emissions are approximately 4,039 and 8,100 tCO_2/year. CEA's national grid average is 0.675 tCO_2/MWh for FY 2025–26. IPCC natural gas is 0.0561 tCO_2/GJ (net calorific basis). This is a CO_2-only calculation. A reporting inventory would include material non-CO_2 gases and other sources. Market-based values assume zero operational generation emissions for qualifying renewable purchases and use the same grid factor as an illustrative proxy for remaining power. Apply the actual contractual factor hierarchy and any appropriate residual mix for reporting. CEA Version 22.0 · IPCC stationary combustion defaults



Three standalone scenarios compared with the same hypothetical baseline.

The moderate package captures much of the commercial upside with ₹7.8 crore of assumed capital and a 2.24-year simple payback. Its savings have three components. Existing load falls by 1.20 GWh, gas use falls by 10,800 GJ and 5 GWh of consumed renewable electricity displaces higher-cost purchases. Compare that package with the strategic scenario on incremental cash flow. The extra ₹16.2 crore of investment yields about ₹1.79 crore more annual net savings, or a roughly 9.1-year incremental simple payback. The strategic package may still serve a deliberate fuel-risk or emissions objective. An investment committee should set the hurdle for that additional spend explicitly.

Under the strategic case, 18,000 GJ of displaced boiler fuel supplies 14,760 GJ of useful heat. A heat pump at a coefficient of 3 adds about 1,367 MWh of electricity. Location-based Scope 2 falls only slightly against the original baseline because this new load offsets most electrical efficiency gains. Scope 1 still falls materially from the gas saving. The market-based result improves further if qualifying renewable attributes accompany the

electricity and the documentation is complete. Both views belong in the decision memo. Keep procurement and physical plant improvements traceable separately, and make a separate consequential estimate if someone needs to assess the project’s effect on grid-system emissions.

A ₹1/kWh adverse change in the landed renewable price cuts moderate-case savings by ₹0.50 crore per year. If actual settlement credits only 4 GWh of the expected 5 GWh and the uncredited portion has zero incremental contractual cost or value, savings decline by ₹0.27 crore. A take-or-pay clause can deepen that loss. At a heat-pump coefficient of 2 instead of 3, strategic-case electricity consumption rises about 683 MWh, adding ₹0.58 crore per year at the grid-price assumption. These checks often matter more to a capital decision than another decimal place on the IRR.

A five-year roadmap that starts on the shop floor

From metering to verified savings

0–6 months	Meter the baseline and fix steam, air and idle losses.
6–18 months	Tender renewable power, improve utility controls and engage priority suppliers.
18–36 months	Pilot heat recovery and electrification. Verify product quality and thermal performance.
36–60 months	Scale the measures that perform. Reassess storage and verify energy and carbon results.

Source · TOPTIER implementation framework

Illustrative implementation sequence and investment gates.

When	Lead team	Priority and dependency	KPI
Months 0–6	Plant operations and energy	High. Baseline meters, steam-trap and leak surveys, batch-level utility mapping	kWh and fuel GJ per good tonne by grade, steam balance, leak closure
Months 6–18	Procurement, finance and engineering	High after metering. Bid for settled renewable volume, tune utilities, request primary supplier data	₹ per usable MWh, credited share, condensate return, top suppliers with footprints
Months 18–36	Engineering, EHS and quality	Medium. Pilot waste heat and electrified low-temperature duties after heat balance and approvals	Verified fuel GJ saved, heat-pump seasonal performance, uptime and batch quality
Months 36–60	COO, finance and sustainability	Conditional. Scale proven measures, evaluate storage and supplier transition	Realized cash savings, Scope 1 and dual Scope 2 results, Scope 3 data coverage

The fastest bill changes usually come from recovered fuel, avoided idle electricity and changes to how equipment is scheduled. Supplier material substitutions and deep electrification can offer longer-term strategic value after quality, supply continuity and customer qualification are secured. As buyers request more evidence, manufacturers with trustworthy batch energy records and clear custody of renewable attributes will be better placed to substantiate product and corporate claims.

TOPTIER’s Perspective on Making Decarbonization Improve Business Performance

Start with the avoidable energy per batch. Then match the lowest landed-cost renewable mix to the load that remains. Screen heat recovery before electrifying the entire steam header. Set a separate hurdle for batteries, hydrogen and other capital-intensive options. Rank them against the job they can perform, whether that is lower peak demand, resilience, useful heat or an independently verified emissions reduction. This sequence gives finance a way to test the economics and gives plant teams a way to protect reliability.

A useful starting point for leadership is one year of bills and interval data, a process and utility flow map, monthly fuel and output records, and a list of purchased materials by tonnes and spend. Together they show where a plant can save now, where it can compete for better power and which investments deserve engineering work.

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The most effective decarbonization strategy is not necessarily the one with the most advanced technology. It is the one that delivers the right combination of energy efficiency, commercial savings, operational reliability, and measurable carbon reduction.