

Commercial RPM economics and bankability

“ The numbers behind the Commercial RPM: where NFE's margin comes from, the Worship Harvest Phase 2 model, the customer-size threshold, and how a project can be financed. These are internal screening figures, not quotes or investment commitments. Model built 18 Sep 2026; terms updated to 21 Oct 2026. Owner: Aaron Tushabe.

Summary

- NFE charges the utility tariff, so its margin is **the grid electricity it no longer has to buy**: solar used directly in the daytime, and solar stored for the 18:00–24:00 peak. The margin sits inside the customer's existing price, not on top of it.
- **Worship Harvest base case** (120 kWh / 50 kW / 40 kWp; CAPEX modelled at UGX 142.8m): revenue UGX 47.0m/year, avoided grid purchases UGX 34.8m/year, **cash flow available for debt service (CFADS) UGX 24.5m/year, project return (IRR) about 15%** over 15 years.
- Financing works with **shilling debt at 12% or less over 10 years or more** (debt service cover, DSCR, of 1.6–1.9x). At ordinary commercial rates of about 18–19%, DSCR falls to about 1.25x and the equity return to about 10%.
- First projects: **50–55% debt**, a 6-month debt service reserve, and a 15-year customer contract. Later, pool sites into a portfolio SPV.

Terms are defined in the [NFE Commercial RPM Finance Glossary](#).

1. Where the margin comes from

RPM margin per kWh = (customer revenue – grid purchases – RPM operating costs) ÷ kWh sold

- Grid electricity NFE passes through at the same tariff earns nothing.
- Solar used directly replaces shoulder-rate grid electricity (UGX 562.1/kWh).
- Solar stored in the battery and used in the evening replaces peak-rate electricity (UGX 666.5/kWh), after about 10% round-trip losses.

- The battery cycles every day, so reliability, solar shifting and peak avoidance all come from the same asset.
- NFE has to be the billing layer for the facility's electricity. If the customer kept paying UEDCL for normal grid power and bought only backup power from NFE, this margin would not exist.

Charging the battery from the grid off-peak to sell at peak adds a little, but it is not the investment case (see [Business Models for the NFE Microgrid OS](#)).

2. Model structure

Customer → Load → System → Dispatch → Economics → Financing

- **Customer:** tariff, monthly bill, generator costs, outage frequency and cost, credit quality
- **Load:** annual and monthly kWh, peak/shoulder/off-peak split, maximum kW, critical kW, interval profile
- **System:** solar kWp, battery kWh and kW, inverter kW, CAPEX, useful life
- **Dispatch:** solar used directly, battery throughput, grid and generator kWh, curtailed solar, unserved energy
- **Economics:** revenue, energy costs, O&M, replacement reserve, CFADS, project IRR
- **Financing:** debt share, rate and tenor, DSCR, debt service reserve, equity IRR, buyout schedule

There is no shared spreadsheet yet; the calculations so far were done in Aaron's ChatGPT working session.

3. Base assumptions

Assumption	Base value	Validate with
Customer tariff	Applicable Code 10.2 time-of-use tariff. Q3 2026, before VAT: peak 666.5, shoulder 562.1, off-peak 429.7 UGX/kWh. Q4 2026 reportedly unchanged.	ERA schedule at each proposal date
Load (Worship Harvest)	82,940 kWh/year; 29% peak / 52% shoulder / 19% off-peak	12 months of bills and Phase 1 interval data
Solar yield	1,500 kWh/kWp/year (a Soroti solar plant averaged ~1,670)	Site-specific PV simulation
Battery	90% round-trip efficiency; 90% depth of discharge	Supplier datasheet and warranty
Inverter efficiency	95%	Datasheet

Assumption	Base value	Validate with
Reliability reserve	15% on battery sizing	SLA definition
Routine O&M	UGX 2.14m/year (~1.5% of CAPEX)	O&M quotes
NFE monitoring, billing and admin	UGX 1.2m per site per year	NFE operating costs
Battery and inverter replacement reserve	UGX 6.91m/year (~5% of CAPEX)	Warranty terms, cycle life, replacement prices
CAPEX	UGX 120–145m (model run at 142.8m)	At least two EPC/vendor quotes
Contract term	15 years; no residual value; no export income	Contract
Tariff escalation	None (real terms)	Indexation clause
Target project return	15%	Investment decision

4. Worship Harvest results

Energy flows (40 kWp)

Flow	kWh/year
Customer consumption	82,940
Solar production (40 kWp × 1,500)	60,000
Peak load supplied through the battery	24,207
Solar used directly against shoulder load	~33,100
Grid purchases replaced	~57,300
Grid purchases remaining	~25,600
Share of consumption met by solar and battery	~69%

Cash flow (bankability model, 40 kWp)

Item	UGX m/year
Customer energy revenue, before VAT	47.0
Grid electricity NFE still buys	(12.3)
Avoided grid purchases (gross margin)	34.77
Routine O&M	(2.14)

Item	UGX m/year
NFE monitoring, billing and admin	(1.20)
Battery and inverter replacement reserve	(6.91)
CFADS	24.52
CFADS per kWh sold	~UGX 296
Project IRR, 15 years, before financing	~15.1%

Solar size sensitivity (first, lighter model)

Solar	CAPEX (UGX m)	Annual contribution (UGX m)	Margin per kWh (UGX)	15-year IRR
32 kWp	135.5	23.4	282	15.2%
36 kWp	139.1	26.7	322	17.5%
40 kWp	142.8	30.0	361	19.6%
~46 kWp	148.6	35.2	425	22.6%

The first model combined O&M and replacements at 2.5% of CAPEX. The bankability model funds battery and inverter replacement explicitly, which lowers the 40 kWp return from about 19.6% to about 15.1%. The "around 20%" return discussed at the [19 Sep check-in](#) came from the first model.

5. Customer-size threshold

The model was scaled to hypothetical customers with Worship Harvest's load shape, sizing the battery, inverter and solar for each and checking the 15-year return (first, lighter model):

Monthly consumption	Result at the 15% target
1.0 MWh	Below target
1.25 MWh	Below target
~1.5 MWh	About 15% (break-even ~1,490 kWh/month)
2.0 MWh	Attractive (for example ~30 kWh battery, 15 kW inverter, ~12 kWp solar)
3.0 MWh	Strong
5.0 MWh	Very good

Downside case	Break-even consumption
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Base	~1.49 MWh/month
Solar yield 1,350 kWh/kWp	~1.68
CAPEX +15%	~2.09
Required return 20%	~2.24
Reliability reserve 30%	~1.64
Site overhead UGX 2m/year	~1.81

Several reasonable downside cases land near 2 MWh/month, which is why it became the screening threshold. **Caveat:** these runs used the lighter replacement assumption. Re-run them with the bankability assumptions and the 50% minimum payment before treating 2 MWh/month as firm.

6. Financing

Structures compared

CAPEX UGX 142.8m, CFADS UGX 24.52m/year, 10-year loan with level annual repayments:

Debt share	Rate	Debt service (UGX m/year)	DSCR	Equity IRR
60%	12%	15.16	1.62x	~15.7%
60%	18.7% (commercial bank)	19.54	1.25x	~10%
50%	18.7% (commercial bank)	16.28	1.51x	~11%
60%	10%	13.94	1.76x	~17.4%
60%	8%	12.77	1.92x	~19.2%
55%	12%	13.90	1.76x	~15.6-16.0%
50%	12%	12.64	1.94x	Not calculated

Equity IRR treats the 6-month debt service reserve as cash tied up for the term. In the 60% / 12% case, LLCR is about 1.62x and PLCR about 1.95x.

Rates context: Bank of Uganda reported weighted shilling lending rates of about 18.7% in Q4 2025, and shilling loans averaged 17.9% in August 2026. On 14 Oct 2026 the Central Bank Rate rose from 9.75% to 12% ([Macro outlook](#)), so commercial debt is likely dearer now. That strengthens the case for concessional finance.

Volume risk (60% debt at 12%)

Useful energy vs today	CFADS (UGX m)	DSCR
Base	24.52	1.62x
–5%	22.78	1.50x
–10%	21.04	1.39x
–15%	19.30	1.27x
–20%	17.56	1.16x

A lender wanting DSCR of at least 1.30x needs about 86% of today's throughput (about 5.95 MWh/month). At 50% debt, a 20% drop still leaves about 1.39x. The 50% minimum monthly payment (agreed 6 Oct) adds a revenue floor. **This table hasn't been re-run with it yet.**

Recommended structure for the first projects

Item	Position
Debt	50–55% of CAPEX, shilling, 10 years or more, 12% or less
Equity (NFE and investors)	45–50%
Debt service reserve (DSRA)	6 months of debt service
Customer contract	15 years
Customer deposit	About 2 months of electricity bills
Minimum payment	50% of the reference monthly energy charge (agreed 6 Oct)
Early termination	Payment covering outstanding debt, demobilisation and a defined share of unrecovered investment
Export income	None in the base case

At 55% debt: debt UGX 78.5m, equity plus DSRA about UGX 71m, debt service UGX 13.9m/year, DSCR 1.76x.

Capital stack to aim for

- 50–60% concessional or project debt at 8–12% in shillings, over 8–10 years or more
- 30–40% NFE and investor equity
- 0–20% climate grant, guarantee or first-loss capital

One candidate is Uganda Development Bank's Climate Finance Facility, which describes concessional debt, equity, guarantees and grants, and supports solar mini-grid projects. Once 5–10 sites have an operating history, pool them in a portfolio SPV (for example 20 sites × UGX 150m ≈ UGX 3bn) with portfolio-level DSCR and a central reserve. Lenders prefer that to financing one site

at a time.

7. Ownership option and buyout

The year-5 purchase price must at least repay the outstanding senior debt and any prepayment costs, plus the NFE residual value agreed at signing. Outstanding debt in the 60% / 12% / 10-year case:

End of year	Senior debt outstanding
3	UGX 69.2m
5	UGX 54.7m
8	UGX 25.6m
10	0

8. Cash-flow waterfall

1. The customer pays NFE for metered electricity (or the minimum payment).
2. NFE (or the SPV) pays for grid electricity and other energy costs.
3. Routine O&M and operating costs are paid.
4. The battery and inverter replacement reserve is funded.
5. What remains is CFADS.
6. Scheduled senior debt service is paid.
7. The debt service reserve is topped up if needed.
8. The rest goes to NFE and equity investors.

9. Risks and mitigations

Risk	Mitigation
Customer uses less electricity	50% minimum monthly payment; lower debt on early sites; credit review; early termination payment
Tariff changes	Mirror the Code 10.2 structure; define indexation in the contract
Late or missed payments	Payment history, deposit, remote metering, clear default procedures, a diversified portfolio
Battery and inverter replacement	Explicit reserve, manufacturer warranties, standard equipment, remote health monitoring

Risk	Mitigation
Solar or storage underperforms	Conservative yield, commissioning tests, reserve margins
Peak demand underestimated	Phase 1 metering after the grid/generator changeover; size the inverter from measured kW
Regulatory	ERA certificate of registration for the microgrid before operation
Construction	Competitive quotes, fixed-price scope where possible, acceptance tests, EPC warranties
Currency	Equipment is priced in dollars; the shilling has fallen about 12% this year (Macro outlook)

10. Equipment cost benchmarks (Sep–Oct 2026)

Item	Price	Source and caveat
61.44 kWh high-voltage LFP battery (Felicity)	~UGX 32.77m incl. VAT	Uganda retail listing, Sep 2026
50 kW three-phase hybrid inverter (Felicity)	~UGX 14–15m	Uganda retail listings, Sep 2026
580 W solar module (Felicity)	~UGX 405,000 (~UGX 700/W)	Uganda retail listing, Sep 2026
600 W mono solar module	UGX 370,000 (~UGX 617/W), VAT not shown	Muden Systems quote, 19 Oct 2026 (page)
Packaged 120 kWh / 50 kW / 55 kWp C&I system	~UGX 144.69m incl. VAT	Uganda retail listing, Sep 2026
Packaged 60 kWh / 50 kW / 26.4 kWp system	~UGX 96m	Uganda retail listing, Sep 2026
Protection, changeover, mounting, cabling, switchgear	~UGX 8–12m	Estimate
NFE metering, controls and installation	~UGX 6–9m	Estimate
SRNE equipment for a ~120 kWh / 60 kW / 40 kWp system	~US\$30,750, before the remaining installation costs	NFE's SRNE wholesale price list (Uganda), 23 Jul 2026

These are budget-brand retail prices. Hillary pointed out on 12 Sep that commercial customers and EPCs may expect SMA- or BYD-class equipment, so get quotes for that too. Dollar-priced equipment follows the shilling within weeks.

Installed planning allowances used for the Oct 2026 funding target: about US\$15,000 for a smaller commercial site (30–40 kWh), US\$25,000 for a medium site (60–80 kWh) and US\$45,000 for a Worship Harvest-scale site (~120 kWh), each including solar, inverters and installation.

Worship Harvest is one of the larger sites, not the typical one. See [Funding target](#).

How the Worship Harvest CAPEX moved: UGX 118m in the first estimate (~28 kWp) → UGX 135.5m (32 kWp) → UGX 142.8m (40 kWp, with more conservative installation, project and contingency allowances). Present it as UGX 120–145m until EPC quotes arrive.

11. Before an investment decision

- ☐ Replace CAPEX with at least two EPC quotes, including an industrial-grade option
- ☐ 12 months of bills plus Phase 1 interval data, including generator-supplied load
- ☐ Site-specific solar simulation
- ☐ Lender term sheets (rate, tenor, minimum DSCR, reserve requirements)
- ☐ Re-run the threshold and volume-risk tables with the 50% minimum payment
- ☐ Move from annual averages to a monthly or hourly dispatch model
- ☐ Never quote the IRR, DSCR or 2 MWh threshold without the assumptions behind them; they are outputs of this model, not constants

Source: Aaron's ChatGPT working session "[Commercial RPM Modeling](#)" (18 Sep–21 Oct 2026). Last reviewed 21 October 2026 by Aaron Tushabe.

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