Feasibility study of two DC systems

Bothnia Green Energy Project

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PROJECT ORGANISATION

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FRONT PAGE PICTURE

Shout-out to Federico Beccari for front page picture (via Unsplashed).

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1 Summary and introduction

Charging infrastructure systems that incorporate photovoltaic (PV) and battery energy storage systems (BESS) that are coupled via alternative current (AC) or direct current (DC) have been studied. DC-systems have potential energy savings via higher efficiency due to fewer conversion steps, with lower associated conversion losses.

While the DC-system can look simpler, with a reduced number of components, the investment cost necessarily doesn't decrease, mainly due to somewhat higher unit prices. However, for cases with relatively high utilization of the charging infrastructure, especially so coupled with high power charging, the operational costs and high energy throughput constitute the overwhelming part of the total cost of ownership (TCO).

DC-systems become more attractive than AC-systems for:

- Green-field installations without legacy infrastructure
- High loads
- High utilization degree
- High electricity costs
- Scenarios where expansion of the system is envisioned
- PV and/or BESS integration projects
- Low depreciation rates
- High carbon intensity electricity mixes

The evaluated systems relative energy savings are dependent both on size and EV-demand prognoses, but ~2-5% units for charging in the typical stand-alone scenario can be attained. With PV and BESS integration, losses originating from PV can be cut by approximately half for the DC-system, where the total system efficiency depends on the balance between self-produced and grid-fed energy.

For systems where legacy infrastructure can accommodate added loads and where utilization and power of chargers are relatively low, the energy efficiency yields doesn't necessarily warrant the added costs over the system lifetime.

With high utilization of equipment, e.g. case where on-site industrial traffic is electrified or other cases where heavy charging needs can be scheduled – the cost of the charging infrastructure becomes very small compared to the cost of the energy bought. The electrical energy bought in Nordic settings is in turn substantially cheaper than the fossil fuels alternative.

While the costs of investment in electrical vehicles have not been in the scope of this study; both lower cost of charging and availability of charging infrastructure helps incentivize investments in heavier electrical vehicles to help decarbonize both traffic and on-site industrial services.

2 Methods, data and assumptions

The results of the report are based on measured, extracted or constructed data sets from e.g. use cases, simulated PV energy generation, as well as a range of parameters regarding efficiencies and costs for various equipment. The parameters have primarily been loaded from supplied offers on equipment, or secondarily from previous offers and experience values from previous projects, and in last case from high level market trends and analysis. For efficiencies of various system setups, a review of equipment has been used as a span, and weighted averages have been used for the base-case parameter.

For dimensioning of PV and BESS systems, the sizing of the respective systems has been scaled and optimized from either economic parameters or energy utilization.

Carbon footprint of electricity has been extracted from *electricity maps* for full year 2024 (not on hourly resolution) for each electricity area. Fuels' emissions has been taken as the generic carbon conversion (complete combustion of standard qualities).

2.1 Consumption profiles

Load profiles for facility energy usage have been imported from available data for reference cases.

For the electric vehicle profiles in Umeå, data from similar compound have been used, and qualitatively assessed to understand the behavior from the aggregated data. See further under section on charging infrastructure at Renen. Additional data has been extracted from 2025 Jan-Aug, where Sep-Dec have been extrapolated assuming a symmetric behavior during fall/winter as for winter/spring. The energy usage for the electric vehicles' charging has increased by a factor of 3.5.

For the electrified fleet at Alholmen Industrial Park it is divided in 2 overarching categories – on-site (subdivided into forklifts, front-loaders etc.) and external, where external are broken into the categories utilized in the demand study, namely; passenger cars, medium-duty, light trucks and heavy trucks. All sub-categories have their specific load needs based on the demand study coupled with indicated usage patters and driving ranges.

A factor has been implemented into the calculation tool to enable scaling of the consumption patterns, as to easily assess impact of scenarios with higher or lower EV growth rates and the impact on total cost of ownership.

2.2 PV-generation, BESS and energy balance

Solar energy electricity generation have been simulated in three cases; south-faced angled mounting for Umeå, similar to existing array, and south-faced as well as east/west-faced mounting for Jakobstad.

In the simulation, surplus PV energy stored in battery system is stored until an energy balance deficit occurs, whereupon the batteries are discharged to cover this as much as possible. This part of the calculation indicates how well generated PV energy can be utilized but does not address specifically the power balance impact. That is described further in the following sections.

Efficiency impact on appliance levels is implemented from a set list of mid-range efficiencies (tunable) to highlight the differences between AC- and DC-systems as a function of which path the current takes (e.g. grid-to-charger, PV-to-charger, PV-to-BESS-to-charger) including the various efficiency losses within that path.

2.3 Exclusions and comments

Not all functions of the system have been possible to implement in the project frame. Those can be covered in a deeper analysis at a higher project maturity level, and cover e.g.:

- Self-discharge and efficiency variation due to battery status: Relevant for cases with longer storage times and for more detailed simulation, if required.

- Dynamic efficiency loss: Load dependent efficiency losses and BESS state of charge and charge-rate loss function are quantitatively excluded and have been treated only qualitatively in the discussion.

- Single vehicle addressability with individual SoCs: Computationally demanding and unsuitable for the simple calculation format. While this gives better granularity on charging infrastructure utilization and que times. This gives little value at the current data resolution level and is treated qualitatively by experiences data.

- No LCAs (life-cycle assessment) have been conducted or used for CO2 footprint. Only commented on from a qualitative perspective. An extended scope could include LCA figures, which would increase the CO2-footprint when also production and transportation of fuel, as well as other emissions, are included.

3 DC and AC systems

3.1 General description

The two types of systems studied are referring to which kind of current is carrying out the distribution of the power within the local area. The AC-system is the one we are well acquainted with from e.g. our homes. Here, the voltage is transformed from some higher voltage at a substation (typically somewhere nearby in the neighborhood) to our system voltage 230 VAC per phase (400 VAC three phase). Where we need to drive DC-loads like LEDs, computers or other electronics, battery charging, or even e.g. heat pumps, we have either an AC-DC-inverter built into the equipment or a dedicated small inverter with a cord, see top panel of figure below for reference.

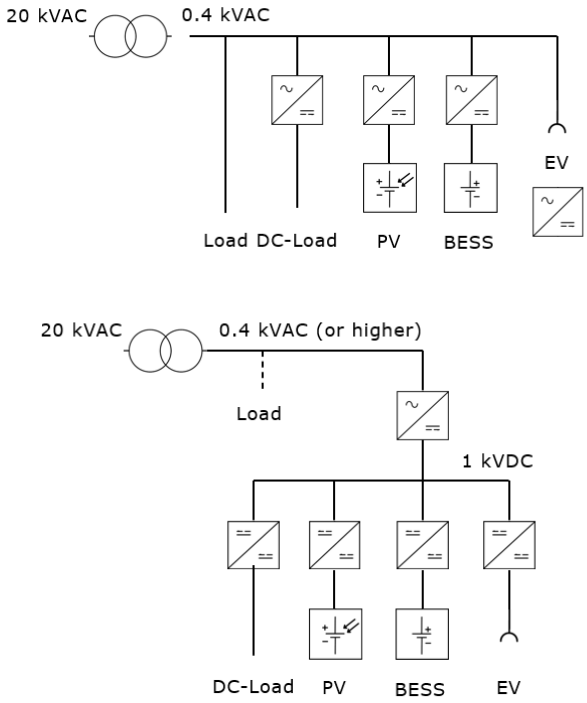

Figure 1. Schematic examples of (top) AC-distribution and (bottom) DC-distribution systems.

In this manner, all inverters are smaller than what a central one would be, and also potential solar energy or battery energy storage systems would need to be converted from the native DC, to AC and back to DC before being used in a DC-load. These conversions are typically quite effective, on order between 90-97%, but compounding quickly when multiple passes are required. EV charging can be carried out either by AC and utilizing the onboard charger of the car (generally fairly low efficiency) or by previous conversion to DC and hooking it up directly to the DC-circuitry of the EV. This is for instance required for fast charging at larger installation, disregarding the distribution grid current type. DC-chargers can be either compatible with the DC-bus voltage and have internal protection circuitry, or require a DC-DC-rectifier. Typical direct DC-bus connected DC-chargers utilize a voltage level that is somewhat lower (~700 VDC) than the 1 kVDC represented here. This should be addressed when in more detailed design phase.

The DC-grid instead utilize direct current as distribution current, a larger central inverter (lower cost per kW, higher efficiency than smaller ones) and several smaller DC-DC-converters to adjust voltage with a generally higher efficiency than AC-DC-conversion.

Also being able to increase the voltage allows for use of thinner cables with maintained losses, or having lower losses with same volume of cables. Having a lower efficiency loss in several steps can quickly give substantial energy savings. If solar energy is stored in battery and later used to charge a car, the losses may be e.g. 20% for an AC coupled system, and only 10% for a DC system.

*T*he secondary AC voltage *can also be adjusted* to match better the peak voltage of the AC side to the DC voltage, which can lower conversion losses. Central inverters may be adapted to higher voltages, e.g. SMA battery central inverters, where models allow up to 624 VAC input.

3.2 Detailed system buildup

The full buildup of the system will depend on many options; prioritization in load management, control philosophies, size, energy sharing between areas, and others. The system represented by the single line diagram below has been used as a base case for the DC-grids.

The main DC-bus voltage is higher to allow efficient distribution of energy. Voltage stability and current quality is maintained with filters (LC) and capacitance (BESS/supercaps). DC-voltage conversion is performed with DC-DC-rectifiers per relevant units.

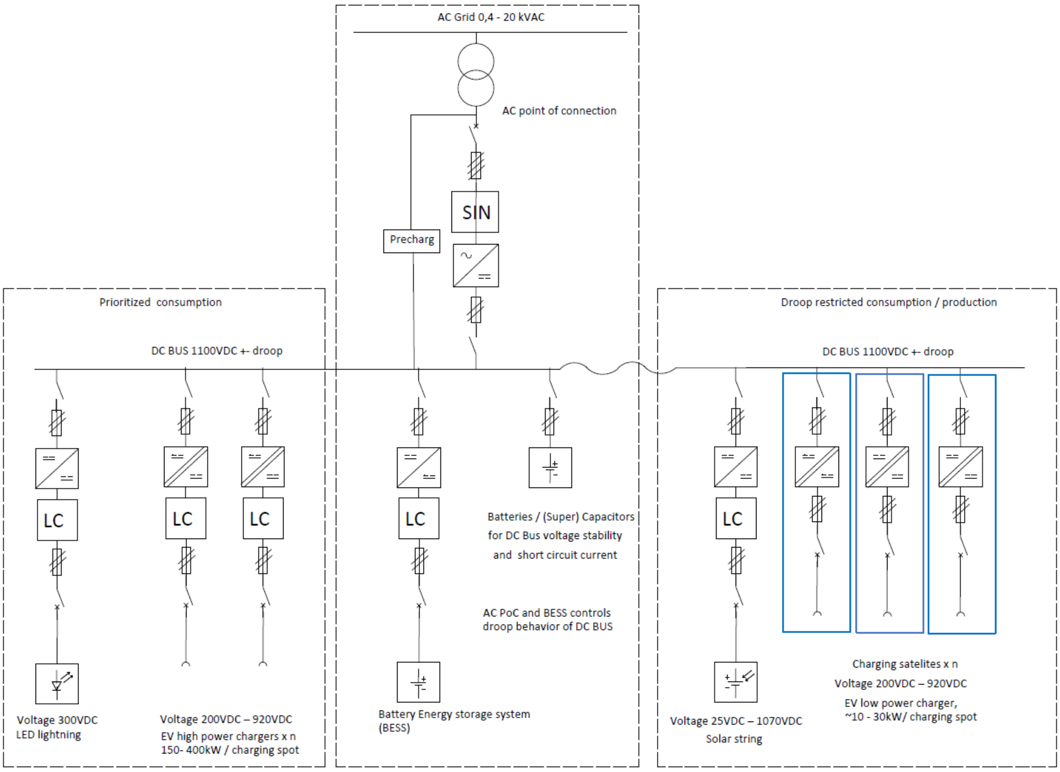

Figure 2. Single line diagram used as basis for the AIP case – (project input, prepared by M. Foxell and reviewed by Victor Wistbacka).

The system is droop controlled, meaning each controlled component responds to the voltage within the grid; e.g. a small increase in voltage indicate a power surplus, allowing additional charging, while a voltage drop indicates less available power. Setting various response functions for prioritized and non-priority loads allows a robust control system without a central point of fault (in terms of control).

Other layers of control is applied on a unit level, e.g. EV or battery charge and other parameters like electricity price. As the droop control is dependent on voltage drops/rises within the system which could work even without central control, the system is easily expandable. However, it is sensitive to introduction of large voltage drops, e.g. long or cheaply dimensioned cables. The system is especially suitable for larger installation where the central control complexity would be very high – it would be easy to expand with additional e.g. charging points.

3.3 Efficiencies of equipment

For a variety of equipment and manufacturers, large ranges of efficiencies can be found. This parameter arguably affects the relative system operational cost and energy use the most.

For power electronics in general there is a power dependence on efficiency. This applies to converting between AC-DC, or voltage levels within AC-AC or DC-DC, as well as altering the quality of the supply (e.g. filtering). Typically, peak efficiency is given but the behavior at low or high loads can vastly differ from the peak case.

There are some easily accessible and designable parameters that are under fair control, those mainly relate to larger inverters, rectifiers and transformers that comes with data sheet and standardization of test protocols, those typically have efficiency around or above 95% efficiency at peak performance, and still 90%+ efficiency at relatively modest loads. and cabling (design criteria, generally 1-4%).

There are also losses in the general electrical infrastructure such as switchboards, filters and minor components that are not as easily accessible but display relatively low losses in most cases.

The largest gap and highest discrepancy in efficiencies are observed in the onboard charging efficiency for AC-charging scenarios. While some boast with high peak efficiencies up to ca 96%, and do display power dependencies that for the full reasonable range (10%+ load) is above 90%, other examination of on-board chargers displays a vastly lower efficiency. An academic paper from 2021 presents possibly the best overview (see page 8)[1], summarizing 34 vehicles and their onboard charger efficiencies. Those ranges from the worst 54-77% (min-max-efficiency) to the best 91-93%, with an average of ca 81-89% window, and median between 85-90%. Noteworthy that the worst efficiency was not from the older models, but from a 2022 vehicle.

With such large spans, a definitive value to pick is not straightforward. To a representative figure for the expected outcome at 2030, for which the project has aimed toward for the demand study, expectation might be that onboard charging may be in the median range or somewhat higher. Here, 89% is used as reference number for further calculations – but it should be clear that this specific number has a very large impact on the comparability of the two systems.

[1] *Experimental validation of onboard electric vehicle chargers to improve the efficiency of smart charging operation*, Martinelli et.al., Sustainable Energy Technologies and Assessments, Volume 60, December 2023, 103512

For the components the following settings and typical ranges have been tested:

Table 1. List of used parameters for efficiencies.

Item	Efficiency	Losses	Range
MVAC/LVAC transformer	98,0%	2,0%	97-99%
AC/DC-bidirectional inverter	95,0%	5,0%	92-98%
DC-DC-converter/rectifier	97,5%	2,5%	96-99,5%
AC/DC central inverter	96,5%	3,5%	95-98%
Distribution LVAC	98,0%	2,0%	96-99%
Distribution LVDC	99,0%	1,0%	97-99%
LC-filter (if not incl. in rectifier/inverter)	98,5%	1,5%	95-99%
AC-charging	89%	11,0%	60-94%
DC-charger	96%	4,0%	94-98%

Utilizing the efficiencies in the list, and acknowledging that the efficiency of several step processes is the product of the various parts, the overall efficiencies of various processes can be summarized as:

Table 2. Representative efficiencies for various processes.

	AC	DC
Grid (excl. transformer) to EV	87%	92%
PV to EV	79%	90%
PV to BESS to EV	71%	86%
Grid (excl. transformer) to BESS to EV	75%	85%

The exact ranges can vary substantially for each depending on things like internal distances between components, but also in what part of the efficiency range from the first table that the actual product resembles.

It is anyhow clear from the table that there are considerable differences between the two types of systems if mid-range products are selected.

Note that the battery internal round-trip efficiency is excluded from those values; it is same for both cases, and is around 98% (only DC-side), but is further complicated by specific product differences, load behavior, state of charge, temperature and if auxiliary cooling is employed or not. To model all those in detail is outside the scope of this study.

3.4 Safety considerations

DC-systems are less standardized compared to AC-systems, especially so the higher voltages envisioned in a distribution grid (as compared to e.g. 12-48 VDC systems). The safety standards and products are evolving and can be implemented to attain a safe system; especially the numerous PV installations have increased awareness amongst e.g. installers.

Nevertheless, some care is required, that are not as problematic or exotic in AC-systems, regarding e.g. handling of thermal stresses, DC-specific circuit breakers and earth protection (RCD), and more technically challenging to get rapid overcurrent protection. Arc extinction is possibly the biggest difference, as the current in DC doesn’t oscillate through zero voltage, the arc is more easily sustained by continuously ionizing the air which can produce quite substantial and long arcs.

While this topic is of high importance, it is not specifically covered in the scope of the project. Previous work on standardization of charging infrastructure components allows for safe installation, but care should be taken in the selection of the design and installation teams.

3.5 Carbon footprint

AC-chargers suppliers seem to indicate ranges of 100-150 kgCO2/unit for the chargers, e.g. Easee (110 kg 2022, 140 kg 2023). The DC-charging points are lighter, and as such warrant a somewhat lower CO2 footprint (materials have high impact). Central inverters from academic research[2] indicates ca 2-4 kgCO2eq/kW. In total, the difference is likely to be similar, or less than 50 kgCO2eq/charger, between AC- and DC-systems. Full EPDs have not been extensively studied within the scope. For high power chargers, that require DC-infrastructure (locally or centralized) for either case, the impacts of equipment is likely to cause less difference between the cases.

For the example with 50 chargers of 10 kW, up to ca 2.5 tonCO2eq may be feasible in favor of DC-system, but it is a very crude estimate.

With a high average utilization of 20% on a yearly basis, the energy savings with 5% efficiency gain, at 500 kW would correspond to ca 43 MWh/year, or ca 3.2 tonCO2eq/year for Finland grid average of 76 gCO2eq/kWh in 2024. I.e., the impact of installation differences is likely to be surpassed within 2 years and constitute less than 10% of lifetime differences. In the lower carbon mix in Umeå (15 gCO2eq/kWh), the operational savings are on levels of single tonCO2eq/year.

To couple these numbers to something relatable, a relatively standard gasoline car would exhaust ca 1.5 kgCO2eq/10km, or 1.5-3 tonCO2eq if driving ca 10-20 000 km/year. If the charging infrastructure can incentivize 1 person to convert to EV, that savings will be on the same order of magnitude with the differences between the scenarios in installation footprint and also similar to the savings in Finland between the systems on an operational footprint.

The vehicle production itself will have an impact as well but is out of scope here. But it should be noted that the big impact of the charging infrastructure on carbon footprint is not from selecting AC- or DC-coupled system, but in the incentive for switching to electric cars. Changing heavy traffic to electric has a substantially higher impact due to both size and range driven.

[2] *Emissions life cycle assessment of charging infrastructures for electric buses*, Surawski et. al, Sustainable Energy Technologies and Assessments, Volume 48, December 2021

4 Multi-story parking garage – Renen

The garage Renen (meaning "the raindeer") is in design and construction phase, and has a similarly sized predecessor garages that has been the basis of estimation of consumption figures. Two scenarios have been evaluated; where the second option has been implemented in a late project stage with additional data and revised system build-up.

Scenario 1: The system parameters to be incorporated is as follows:

- Low power chargers (11 kW) 30 pcs
- High power charges 0 pcs
- Solar power up to 90 kWp (simulated)
- LED lighting
- Engine heaters
- Heating

Scenario 2: The system is simplified, and excludes auxiliary loads (for reasons, see discussion under 4.2).

- Low power chargers (11 kW) 46 pcs
- Solar power up to 90 kWp (simulated)

4.1 Use patterns

The car event (coming/leaving) is not available, but use-data aggregated between several groups of low-power chargers display that:

4.1.1 Scenario 1: Earlier patterns

Clear indicatations that a majority of the charging is occurring during office hours, and that the needed energy per vehicle is relatively modest, as seen by the trailing of the peak loads over several hours. This indicates that the batteries are becoming full; this could be a misinterpretation, as it could also indicate that the cars are leaving, but is supported by the hour-to-hour decrease in power, rather than abrupt movements. While the total charge power doesn't exceed the total cap, the power cap on the subdivided 5 separate groups can very well be masked with their separate load management.

Utilization of the chargers are at relatively low levels, ca 10% of the load balancing limit on peak hours (yearly average), and far below the summed rated power of the chargers. In total ca 43 MWh/year is charged over 22 units of 3.7 kW and 24 units of 11 kW chargers, or 910 kWh/charger/year. This would indicate a utilization degree on yearly basis of 1-3% (for 3.7 and 11 kW chargers respectively) – the distribution between those is not known.

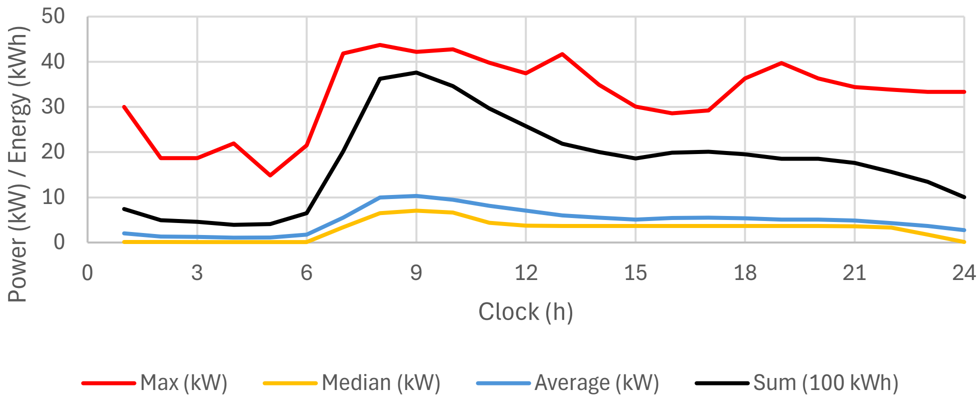

Figure 3. Aggregated parking behaviour at Järnvägsallén with max, median, average (hourly) and summed (x0.01, yearly) consumption.

With a low utilization degree, the energy savings on a DC-grid becomes a smaller portion of the total cost structure and the investment cost becomes more pronounced.

4.1.2 Scenario 2: Substantially increased loads

Comparing the data between Figure 3 and Figure 4 a few trends crystalize:

1. The number of cars and occupancy is improved due to sheer increase in energy charged (an increase by a factor of 3.5, or +250%).
2. The utilization of the charging infrastructure is higher for later data. Seen most easily as the relationship between hourly max and yearly consumption shifts.
3. Off-peak hours increase relatively more than on-peak hours, indicating more charging due to overnight parking. Seen also in slightly more pronounced shoulder around 17.00-18.00.
4. Point 1 and 3 together suggest that nearby inhabitants may have increased their reliance on the local infrastructure and/or acquired more chargeable vehicles.

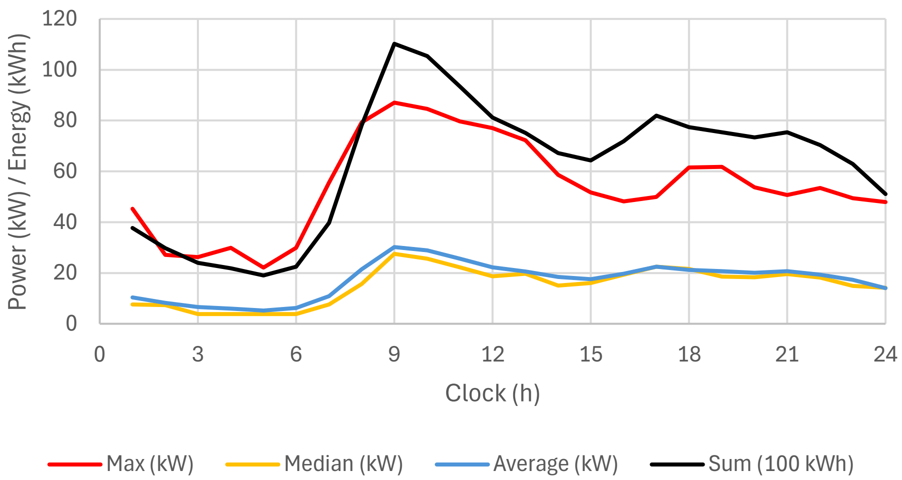

Figure 4. Aggregated parking behaviour at Järnvägsallén with max, median, average (hourly) and summed (x0.01, yearly) consumption.

4.2 System costs

Cost for the system is estimated as:

Table 3. Cost structure for cost estimate.

Item	**Cost**	
11 kW DC-chargers	1980	€
11 kW AC-chargers	1480	€
Central inverter	110	€/kW
Battery (DC)	300	€/kWh
Battery (AC)	600	€/kWh
PV (DC)	700	€/kWp
PV (AC)	900	€/kWp

With the specified costs and additional cost for project management, design, switchboards and 20% contingencies, the 30 charger AC-system is estimated to cost of scenario 1/2 is ca 125/155 k€ and the DC-system ca 145/175 k€ without batteries or solar energy integrated into the system. The service for the system is estimated at ca 5 000 €/year (ca 120 €/charger plus insurances, without payment methods assumed to be same for both AC- and DC-systems). The initial use for scenario 1 are measured from previous object to be ca 42 MWh/year, with a lifetime use of ca 840 MWh over the 20-year expected lifespan. A direct cost of ca 0.17 €/kWh in charging infrastructure for the DC-system and 0.15 €/kWh for the AC-system disregarding service. Service and energy costs (at 0.122 €/kWh incl. tax, and 66.19 €/kW/year in power tariff) adds an additional ca 0.238 €/kWh on year 1 basis to a total.

For the DC-system, the cost of charging is ca 0.341 €/kWh and for AC-system 0.343 €/kWh, discounted over the lifetime with a 6% discount rate and 2% inflation.

Realistically, the load is likely to increase when EV penetration becomes more prevalent. The amount of energy passed through the system has a profound impact on the LCOE for the charging infrastructure, see table below for impact of increasing the charging need with X% compared to 2024 values for reference parking garage.

Table 4. Impact on utilization (load intensity) on LCOE for DC-system above.

Increase	Energy	LCOE	Utilization	Comment
%	MWh/y	€/kWh	%	
Scenario 1	43	0,343	6%	30 chargers
50%	64	0,306	9%	
100%	86	0,261	12%	
200%	125	0,208	18%	
Scenario 2	150	0.191	22%	46 chargers
300%	159	0,183	25%	
500%	215	0,159	37%	

Scenario 2, with slightly more chargers, and with a 250% increase do indeed also fall in the range of the earlier prediction, with 151 MWh/y, an LCOE of 0.191 €/kWh and a utilization of 22%. The very rapid increase is remarkable; and while causes are unknown, improved visibility and following habits, as well as higher charging rates is likely a main contributor, apart from just more chargeable vehicles on-road.

The utilization rate can be increased in two fundamental manners – either by increasing the EV fleet in general or by decreasing the number of chargers. One strategy mentioned previously could be to prepare for an expansion, and connect more chargers as the need arises. A low utilization grade do however allow all chargers to go to maximum power, which boost efficiency compared to if they are severely constricted for the AC case. For the DC case, having a central inverter at low relative power can also decrease efficiency if *e.g.* a single vehicle is charging from the DC-grid. This has not been evaluated further.

When integrating photovoltaics, and comparing to the baseload, including heating, lighting, and engine heaters, the own-usage of solar energy starts to flatten out at around 30-40 kWp for scenario 1, and at slightly larger systems for scenario 2, as seen in the figure below. For sizes of 30+kWp, the increased consumption of scenario 2 improves the own-utilization degree by 10% units. With current trend on consumption, the own consumption PV array is highly likely to increase with time.

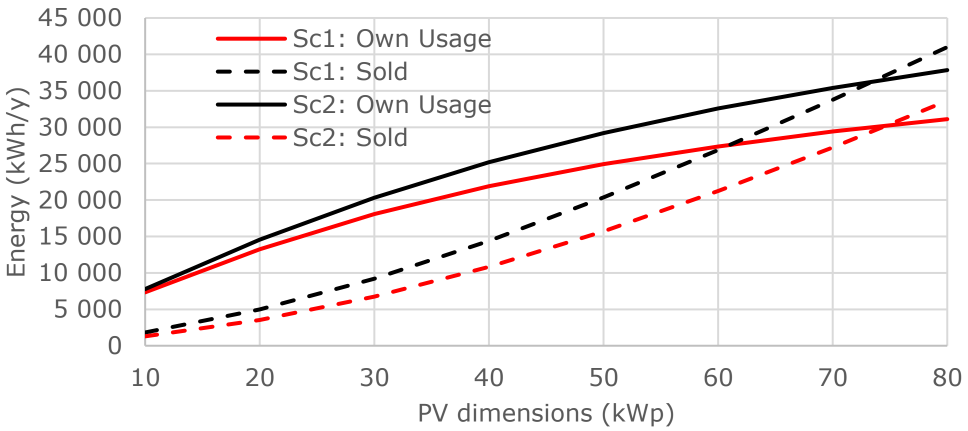

Figure 5. Direct solar energy use and sold solar energy as function of PV array dimensions for scenario 1 and 2.

The other loads have been incorporated on the AC side, and surplus energy is sold at a fixed 0.025 €/kWh. Breaking out the PV installation from the charging infrastructure, the KPIs of the solar installation is seen in the table below, where the net savings/earnings is for year 1, and payback time is discounted over a 40-year period with reinvestments in inverter/DC-DC-rectifier at year 20.

Table 5. PV system size key performance indicators for scenario 1 and 2.

	Scenario 1				**Scenario 2**			
Rated power	**Own use**	**Sold**	**Net**	**Payback**	**Own use**	**Sold**	**Net**	**Payback**
kWp	**kWh/y**	**kWh/y**	**€/y**	**years**	**kWh/y**	**kWh/y**	**€/y**	**years**
10	7 330	1 820	937	14	7 780	1 290	894	11
20	13 242	5 001	1 735	13	14 568	3 529	1 702	12
30	18 079	9 214	2 429	13	20 323	6 754	2 420	13
40	21 907	14 397	3 024	14	25 179	10 838	3 060	14
50	24 921	20 361	3 539	16	29 198	15 722	3 627	15
60	27 361	26 877	3 999	17	32 565	21 228	4 138	16
70	29 400	33 777	4 419	19	35 405	27 238	4 603	18
80	31 107	40 997	4 808	21	37 839	33 636	5 032	19

Again, these numbers do improve with increased EV charging, as own-consumption of energy increases. The longer payback at the lower dimensions are related to higher cost per installed capacity for fixed cost items.

All cases where BESS are included (irrespectively of size) result in a net higher LCOE. This can also be envisioned by recognizing that the impact on the financial sheet is mainly in this scenario from increasing the value of the otherwise sold electricity (by the difference in bought/sold electricity). The potential to shave of consumption peaks, i.e. peak shaving, is present, but with a charging infrastructure which does that itself, the peak shaving is mainly relevant for the building loads. The heating is carried out via a hot water tank, which is in itself also an energy storage, that can be used rather than the more costly battery in terms of €/kWh-capacity. The battery could be better suited in the case where faster charging is required, which has not been envisioned on this site. So, while the battery has a marginal impact on the OPEX, it entails substantial investments not recoverable without further loads or that other types of functions are implemented (e.g. electricity price arbitrage, ancillary services etc.).

4.3 Including other loads in the DC-grid

There is little gains in terms of energy savings of including additional loads. The three types addressed during the study has been LED lighting, heating and engine heaters.

We have not been able to identify any vehicles that has DC-connected engine heaters as base case. Unless standardized in future vehicles, employing engine heaters by DC-grid seems a moot point resulting in additional conversion losses. Standardizing this within the ICE scene before ICEs are phased out also seems improbable.

Resistive heaters may use either AC or DC, while modern heat pumps are likely to have a DC-link which could theoretically benefit in efficiency from connection directly to DC-grid via rectifier. But, products that are DC-compatible at input have not been identified during the project. Theoretically, savings on order of 0.5 MWh/year should be possible compared to AC-distribution. On the other hand, CAPEX difference is unknown; while it could be cheaper in if the equipment could be slimmed, it is potentially more expensive due to customization.

LED lighting is a more realistic load to incorporate. Savings of up to ca 2-5% could be realized[3], however, since LED is low power equipment from start, overall impact of energy savings is relatively low. With ca 4-12 kW depending on LED rating and actual patterns for illumination; difference between the choices between AC or DC fed lighting is on the order of ca 200-500 kWh/year (~50 €/year). Efficiency improvements of higher PV use is minor, especially if the garage is not built in and dark during sunny days.

Lifetime of DC vs AC coupled LEDs have not been addressed; drivers are more likely to give out than the solid-state LEDs. Hence, an extended lifetime/additional lower OPEX may very well be probable for DC-systems, which would have an greater impact than that of energy costs. The incentives to connect the LED lighting directly to the DC-bus will in absence of lifetime data be mainly based on CAPEX or assumptions regarding OPEX. CAPEX can be lower for DC connected system (fewer drivers) but depends on voltage rating and cabling requirements (layout not studied).

Having a mini-DC-grid for the lighting is also possible without the overarching DC-infrastructure; and the voltage could be adjusted to fit the specific units voltage range.

[3] *DC Power grid for buildings*, U. Boeke, M. Wednt, IEEE 2015

Either series need to be matched to bus voltage or parallelization with fundamental voltage.

4.4 Summary – UPAB Renen

4.4.1 Scenario 1

The cost of charging is relatively similar for AC- and DC-systems; and dominated by investment costs. With higher charge needs the DC-grid becomes more attractive. The amount of energy charged in the base-case, 43 MWh/year, is roughly 2-3 full-electric cars that charge from ca 20% to almost full battery per day, or barely 4 hours occupancy on 3 out of 30 chargers (at full power). While this is an unlikely scenario to reoccur daily, it does speak about the sizing of the infrastructure in comparison with the charge need.

For security of supply – even at 250% of base case load, the chargers are less than 5% of time limited by the load balancing if implemented on a 63 A 3-phase fuse, even without batteries. On the other hand, at a low average power, ca 118 kWh/day on average, the potential to cover the charging exclusively with solar and battery is quite good.

4.4.2 Scenario 2

The increase of electricity consumption, even with 30% additional chargers, in total decreases the lifetime cost of charging by ca 30%. It is not visible in the data that there is clipping of the peak power, meaning that a load balancing scheme for the very peak hours could be an attractive alternative to BESS. The number of affected hours is relatively modest even at relatively large restrictions, see Table 1. This can be done in two manners: a) reduced inverter sizing, reducing CAPEX, or b) load balancing restricting the upper limit. The upside of the first is the reduced initial cost. However, the second option allows more flexibility, which seems likely to be needed with current development in consumption figures, and can dynamically be altered when the consumption increases.

Table 6. Number of impacted hours if power is limited to X kW.

Power limit	Impact
kW	h/y
60	152
65	108
70	60
75	39
80	8
87	0

5 Alholmen industrial park (AIP)

The industrial park extends over a large area of ca 2.7x1 km, and includes a variety of industries; where the forest industry is the largest, handling large amount of timber and cellulose. The area houses an industrial harbour and railway to the sawmill among other functions. Below is an overview of the area as well as the larger parking areas encircled.

Figure 6. Satellite image (Google Earth) over AIP area (North is to the left in the picture). The coloured circles are areas with parking spaces. The various areas contain parking spaces as; orange 470, green 155, yellow 250, red 40, purple 146, blue 550, totally ca 1600 spaces.

The area has a well built out 20 kVAC ring grid that can be tapped into for charging infrastructure. This is turn connected in the south-east part to the site to the 110 kVAC grid. The individual connections to the 20 kVAC grid is currently possible to be 1 or 1.5 MW each, and could be increased to 2 MW at later point.

In the project, it was concluded that the connection of production facilities (PV) are generally limited to max 1 MW per connection due to regulations. If surplus at no point exceeds 1 MW and self-utilization is high, a larger PV installation could be envisioned.

Other loads than charging infrastructure was concluded early on to be excluded in this phase of the project due to lack of data for the respective connections currently in use.

5.1 Demand study – use profiles

The current situation and electrification prognosis of the inbound/outbound traffic (external) at AIP are displayed in the table below. The prognosis made by the companies at AIP are more conservative than both the positive growth and optimistic growth scenarios, especially so in the electrification of the heavy traffic.

Table 7. Table from pbi demand study at AIP – displaying by the tenants expected (E), positive growth (PG) and optimistic growth (OG) electrified vehicles around AIP premisses.

Number of EVs per Vehicle Category	2025	2027E	2030E	2027 - PG	2030 - PG	2030 - OG
Passenger Cars	32	97	195	108	195	271
Medium-Duty Vehicles	0	0	3	3	7	15
Light-Duty Vehicles	0	0	5	3	8	15
Heavy-Duty Vehicles	0	0	6	6	17	40

% of EVs of Total Count per Category	2025	2027E	2030E	2027 - PG	2030 - PG	2030 - OG
Passenger Cars	3%	9%	18%	10%	18%	25%
Medium-Duty Vehicles	0%	0%	2%	2%	5%	10%
Light-Duty Vehicles	0%	0%	3%	2%	5%	10%
Heavy-Duty Vehicles	0%	0%	1%	1%	3%	7%

The current EVs are exclusively passenger cars, and selected on-site traffic was not included in the demand study. In all 2030 scenarios the energy requirements are dominated by the heavy-duty trucks, due to a combination of long hauls and high consumption in relation to the lower consumption and short route of the lighter traffic.

The demand study studied the number of vehicles per category, the average and maximum travel distance which is summarized below together with a synthetic mid-way scenario between the conservative and optimistic cases, as to better cover the data range. The results and assumptions on milage (energy needed), typical charge or parking time and power needs are displayed below per category.

Table 8. Demand study prediction for estimate and optimistic growth scenarios in 2030 daily basis, and a mid-way scenario. Note that distribution is on an energy required basis, not number of vehicles.

		Passenger	**Medium duty**	**Light-duty trucks**	**Heavy-duty trucks**
Estimate	Number	195	3	5	6
	Energy	780	40,5	343,75	2160
	Distribution	23%	1%	10%	65%
Mid-way scenario	Number	233	9	10	23
	Energy	932	121,5	687,5	8280
	Distribution	9%	1%	7%	83%
Optimistic growth	Number	271	15	15	40
	Energy	1084	202,5	1031,25	14400
	Distribution	6%	1%	6%	86%
	Distance (km)	~20	~45	~125	~300
	Energy (kWh)	~4	~14	~68	~360
	Time (h)	~6-8	~0.5	~1	~0.5
	Power (kW)	~0.5	~28	~68	~720

While there is likely to be around 200 EVs in 2030, the need to charge the passenger cars will not be on a daily basis – as most traffic averaging less than 20 km round-way trip. This is considerably less than the range of general BEVs, and the energy need per day on average would be approximately 300-700 kWh depending on exact car models and season (i.e. how cold it is).

Two scenarios are possible here:

A. That the owners of the EVs would like to charge the cars when the battery holds somewhere between approximately 30-60% of full capacity depending on their range anxiety. This would imply approximately one charge per week if also minor other excursions are included. Approximately 40 chargers would suffice to cover the need, and with ca 4-9 hours of parking time most vehicles would be covered with 10 kW charger.
B. That a larger charging infrastructure is deployed where more or less all EVs could connect – this would entail a substantial increase in cost – and would be mostly interesting in the case where the chargers are compatible with V2G functions, where the cars would be a part of the energy system and e.g. boost the heavy truck- or mega-charging nodes. With current prices for V2G compatible chargers and the number needed, this option is less economically attractive for now. Also, this would require that V2G use of personal EVs would gain acceptance – which could be done by implementing schemes for subsidized parking or charging for those who participate.

Scenario A is the realistic one at current, which would be amended with a few fast chargers or super-fast-charging units for heavy trucks to enable the actors to start their electrification efforts. Some additional chargers beyond the 40 mentioned would still be required unless a schedule is maintained (e.g. specific days), which would not fit all the EV users and provide fairly poor flexibility.

Given an equal distribution of passenger vehicles for the various areas, the distribution of electrical vehicles, energy need and power requirements would be as below:

Table 9. Passenger EV distribution between areas at even frequency per industry.

Area	Spaces	Potential EV	Energy (kWh/d)	Power (kW)
Green	155	20	121	20
Purple	146	19	114	19
Yellow	250	33	195	33
Red	40	5	31	5
Orange	470	61	367	61
Blue	550	72	429	72
Total	**1611**	**209**	**1257**	**209**

With a relatively low number of heavy vehicles, in most scenarios it would be sufficient with a single high power charging station. However, it should be considered to have additional redundancy for the heavy traffic to remove anxiety and idle-cost for the actors if the charging point will be inaccessible (occupied or out of function due to charger or central inverter error). While it isn’t required from an economical or energy perspective for most of the forecasted scenarios to have more than one charger, it can be a discernible factor for the investment decision of the actor. The charger would in principle be a dual charger to allow up to 700+ kW charging power. Cost example used is a 2x400 kW fully configured charging unit.

It is recommended that most of the heavy charging needs with fast chargers are to be located in two distinct areas, i.e. the interconnected parking spaces in south-east where most traffic are passing through (and also is accessible to external traffic) as well as in the centre of AK where also heavy on-site machinery and unloading of heavy trucks are prevalent. This also offers a redundancy by having the charging-infrastructure in different DC-grids or in grids with multiple connections to the medium-voltage AC-grid, as this also alleviates impact of central inverter failures.

There is no information regarding the electrification needs in the harbour, but this is also an area where additional charging needs may very well occur.

5.1.1 On-site traffic

There is little information regarding the on-site traffic. For this reason, assumptions have been made to include electrified vehicles as follows:

- 8 fork-lifts
- 1 heavy truck for wood-chips
- 1 heavy front loader

The fork-lifts are in this scenario charged via fast-chargers (i.e. no battery swap) and the others are done in dual-mode at 700+ kW.

Mega-chargers are expected to be required if also the largest machinery (timber unloaders) should be electrified without significant down-time.

5.2 Charging infrastructure

The proposed setup of the AIP charging infrastructure is made up of islands of DC-grids located at 2 to 6 different areas. The reason to divide the DC-grids rather than to connect it in one larger grid is due to:

- Longer distances between the areas result in more intrusive digging and cable needs, as well as larger voltage drops which can influence the stability/complexity of a droop control system.
- There is ample access to the higher voltage (20 kVAC) distribution grid, which can be utilized as-is and represent substantially smaller investment with maintained or higher efficiency.

The subdivision is made from both a proximity aspect as well as to aggregate enough number of electrified vehicles for the system to be functional – i.e. that sufficiently many vehicles can be expected in every system without over-investments in various areas. This allows both the higher load on the central inverter to avoid very low loads and poor efficiencies areas of the power-efficiency curve.

It is advisable to invest sufficiently in the individual backbone infrastructure in the various fields to allow for expansion over time, and rather not include all the chargers at once if costs are to be under tighter control. This allow also to get some feedback from the users on the utilization degree on the specific parking areas, as to direct the charging infrastructure to the areas where it is best utilized.

The cost of connecting the various areas are expected to range from 26-100 k€ (blue internally the lowest, green-yellow and purple-red approximately 40-50 k€ and green-orange ca 94 k€), which is to be compared to a new connection to the overlaying medium voltage grid of ca 100 k€ (60 k€ for connection, 40 k€ for transformer). The cost of cabling has been estimated from previous project for excavation, cables and works, and cable dimensions have been estimated with a 1% energy loss acceptance. Utilizing the higher voltage of the 20 kVAC ring is from an efficiency point of view better than to employ a 1100 VDC grid for the longer distances. It can be noted for reference that the alternative of connecting with 400 VAC would be considerably worse in terms of cost performance of the cabling.

5.2.1 Low end case – EV focus

If the heavy charging infrastructure were to be excluded and focus would be on the EV fleet, the cost of charging over the lifetime (utilizing same cost parameters as in Renen case) with connection cost of 100 k€, the LCOE figure is virtually the same for AC and DC charging over the 20-year span, at 0.15 €/kWh if the current infrastructure can be utilized, and 0.18 €/kWh if 2 new connections are employed in the DC-case. The two connection points to be added amounts to ca 60% of the total investment cost. However, the added 200 k€ amounts only to 20% of of the total cost of ownership over the lifetime, where the majority of the OPEX arise from energy purchase, ca 38 k€ for energy and 5 k€ for power on yearly basis. As the power for these cases are relatively low, below ca 150 kW, having it distributed in several areas without new connections would be the most cost effective.

Note that the overall lifetime cost/LCOE for passenger cars and comparing AC and DC charging is dependent on a relatively well filled parking area – where relatively high power per charger is employed, especially for the AC case. If low-load charging is employed (either due to many chargers that are tuned down, or a multitude e.g. single-phase chargers), the energy efficiency would be affected negatively.

Integration of BESS is not relevant for the EV-only focus in current setting. Suboptimization of smaller DC-grids with EV is also unlikely to contribute significantly to OPEX, while entailing large CAPEX, since the parking times are long, meaning durable peaks to cover and substantial energy throughput. Peak management can be performed from a charger perspective at substantially lower cost.

PV integration for EV-only scenario ca 50 kWp of solar energy can be fully absorbed for the conservative estimate case (197 EVs in 2030), before overproduction becomes evident. Note that this is from the emulated use profiles, real use cases will have various impacts from e.g. holidays or maintenance schedules as well as randomness in charging behaviour, that is not incorporated. 90% own consumption is reached at 140 kWp installation if it is east-west-mounted, for south-facing mounting the 140 kWp system self-utilization shrinks to 82%, and 90% is prognostisized with 113 kWp installation.

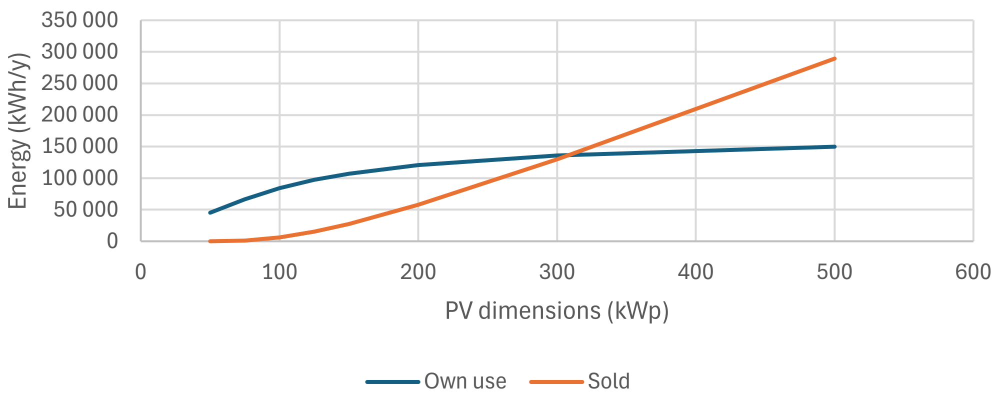

Figure 7. Solar energy utilization with south-ward mounted solar panels for EV only case.

Table 10. PV installation impact on passenger EV case at AIP. With/without tax of 0.05 €/kWh on electrical consumption (impacts the value of replaced energy – not sold energy). Payback calculated with 6% depreciation rate and service costs specifically for PV at 1% of CAPEX.

Rated power kWp	Own use kWh/y	Sold kWh/y	Net €/y	Payback years (w/o tax)	Payback Years (with tax)
50	45 237	28	5 502	18	9
75	66 642	1 202	8 134	18	9
100	84 350	5 907	10 405	19	9
125	97 264	15 192	12 207	20	10
150	107 040	27 476	13 703	22	11
200	120 595	57 771	16 109	24	13
300	135 796	129 740	19 756	40+	18
500	149 775	289 366	25 447	40+	29

The table indicate the payback periods for installations of PV in connection with DC-grid installation, where rectifiers are utilized rather than an DC-AC inverter. When the PV installation also has to carry the cost of the inverter, the payback times for the AC-coupled system is increased.

5.2.2 Heavy load case – 2 DC-islands

The charging infrastructure could be connected to the overlaying medium voltage AC grid in two places; around the south (blue circle – OSTP and UPM Cellu) and in the centre (red+purple circles – UPM, Willhelmina and AK). The heavy on-site charging is carried out in the central area at AK, while trucks are mainly charged at OSTP as a natural traffic central hub.

The installed cost ranges from ca 750-1060 k€ for the systems depending on the exact configuration. Here, the fast chargers at 80-300 kW are priced at 26 k€ per piece, and a 800 kW at 138 k€. Connection and cable costs as above. The resulting outcome for the optimistic growth and estimated growth cases are seen below. Operational expenses apart from energy is estimated between 2-20% of CAPEX, with decreasing percentual cost with higher power chargers, or ca 75-1500 €/unit/year.

Table 11. Two system buildups for the heavy load cases with two DC-grid islands.

		Optimistic growth	Optimistic growth+Onsite	Estimated growth
DC charger 10 kW	#	50	50	30
Fast charger 80-300 kW)	#	4	6	1
Fast charger 800 kW	#	2x2	2x2	1x2
CAPEX	k€	1 058	1 120	741
OPEX (excl. energy)	k€/y	47	50	30
OPEX (incl. energy)	k€/y	630	1 009	167
Energy charged	MWh/y	6 498	11 462	1 498
Charge energy cost total	€/kWh	0,074	0.068	0,096
Cost of charging (exc. Energy)	€/kWh	0,013	0.008	0,039

Again, the total cost of ownership over the 20-year lifetime is dominated in all cases by the energy costs, but considerably more so for the optimistic growth scenarios with or without the on-site traffic, where ca 2 years of charging surpass the initial investment cost.

The cost breakdown is as follows with the indicative pricing utilized:

Table 12. Cost breakdown of case Optimistic growth with onsite traffic.

DC-chargers	99 000	€
DC-fast chargers	104 000	€
DC-ultra chargers	276 000	€
BESS	0	€
PV	0	€
DC-DC-rectifiers	66 000	€
Central inverters	138 754	€
Grid connections	120 000	€
Transformers	80 000	€
Cabling for 2 DC-islands	73 000	€
Other	112 000	€
Total	**1 120 000**	**€**

If DC-bus voltage compatible chargers without requirements on rectifiers are selected, e.g. enteligent or other systems, DC-DC-rectifier costs can be reduced.

When doing the discounting with 6% depreciation rate, the net-present-value of 1% improved efficiency is corresponding to ca 55 k€ - which can be used both to evaluate the lower efficiency AC-system (ca 3-7%) and also when comparing DC-options internally. This highlights the usefulness of comparing not only CAPEX, but also efficiency and eventual OPEX of the equipment, especially in heavy load scenarios.

The corresponding AC system would still require investments in the MVAC-grid, the DC-chargers for fast charging (with inverters centrally or distributed), and the discussion regarding the two options becomes similar to comparing to the DC-systems in previous chapter. Cabling would increase in cost due to high loads at lower voltage.

One major impact if implementing a hybrid system of AC and DC charging is the controllability and ease of load balancing that is affected. With a central inverter and droop control, the fast charging units can be prioritized easily, without extensive control systems. Likewise, the low-power charging infrastructure can be expanded with relative ease.

Implementation of BESS to cover the peak loads in the heavy load scenario with both optimistic growth external traffic and with the on-site traffic would entail quite hefty investment costs for a single 2 MW connection and distributed DC-grid. The exact dimensions to achieve 95% prioritized load security is a guesswork, given the uncertainty in the user profiles, exact vehicle arrival patterns etc. but would be on order of ca 1.5 MW/3 MWh. The investment cost of ca 1 400 k€ to boost those chargers would with current power tariff structure decrease power costs by ca 28 k€/year, not sufficient to be economically motivated in this operational mode. Applying a secondary grid connection for a fraction of the cost would be suggested. This would also allow additional PV to be integrated and decrease distances.

The battery investment is ca 3 times as expensive as the alternative of employing ca 100 V2G compatible chargers (cost ca 4000€/unit added compared to low-power DC-chargers, but also at higher rates of 30 kW), if the connected EV fleet would allow 20 kWh of energy being drawn at 10 kW rate per car on average. How the business case regarding the V2G handling of power extraction is to be done has not been discussed further. The V2G chargers would give additional possibility to maintain a flexible system, while the current cost would be hard to motivate. The most attractive scenario for the V2G application is when intermittent heavy loads are present in connection with constrained connection or high power tariffs that can be countered.

For PV implementation, the heavy use cases would utilize 90%+ of even a 2 MWp PV installation. Larger PV installations have not been evaluated due to restrictions on connection size and while positive, relatively low return on investment in the relatively low-cost energy environment without taxation and low wholesale prices. LCOE figures for the PV array itself is for a 1 MWp array ca 0.048 €/kWh at 6% discount rate over a 40-year lifetime. Being lower than that of the grid energy cost – and utilizing most of the energy directly – installation of PV makes sense economically – while also being a sort of fixed price guarantee for oneself. If energy prices would be expected to fall below ca 0.023 €/kWh, the grid fed energy would be cheaper (including transfer fees etc.).

5.3 Priorities in charging

For all areas, the priority charging will be for the fast chargers for industrial applications, where EVs charge rate will be secondary. With two connections to the overlaying grid, the prioritized loads will be able to charge at full rate if one dual charging point of 800 kW is associated with each area. Even 2x800 kW charging is relatively doable to receive almost full power if the connection is 1500 kW, where the other charging infrastructure would be put on halt for the duration.

5.4 Fuel savings

With the above assumptions on use patterns and fuel usage for the various vehicles, the optimistic growth scenario could result in reduction of fuel usage as below.

Table 13. Indicative fuel savings if actors are incentivized to switch to EV in accordance with the optimistic growth scenario.

Load profile	Fuel type	tonCO2/y	Fuel m3/y
EV	Gasoline	255,6	111
Mix Non-heavy	Diesel	646,0	239
Heavy truck	Diesel	4300,4	1592

5.4.1 Incentives related to fuel and charging costs

Current cost for subsidized diesel is roughly 1.2 €/L which is used for reference below. Utilizing unsubsidized fuel will have a larger impact on the differences. This result in an energy cost of approximately 0.12 €/kWh_{Th} (depending on diesel quality), or ca 0.25-0.40 €/kWh in effective propulsion energy depending on engine efficiency and driving mode. Additionally, the carbon emission trading system 2 (EST2) to be implemented in 2027 will also affect the cost between ca 0.15-0.6 €/L if the trading will be between ca 50-200 €/ton_{CO2}. These figures are well above the cost for supplying energy by electricity by a DC-grid, including the losses in the electric distribution and charging. A heavy truck that can utilize the charging infrastructure can decrease their energy costs by a factor of ca 2-6 depending on which case and what figures are used, higher with EST2 values.

It should be noted that for the larger DC-grid, fleet charging, PV and BESS installation *without a relatively high utilization*, the cost of charging infrastructure can become quite large in comparison, measured as levelized cost of energy for charging. It can therefore be wise to install the base units required but complement the infrastructure along with increase in traffic. The heavy chargers and BESS installations are the most cost driving, but also if a very high number of low power chargers are employed. The PV installation can also be CAPEX intensive, while also generating income (albeit at lower energy pricing in the model), it does not impact the LCEO for charging in quite the same manner – it rather prolongs the return of investment date than raising the LCOE.

6 Conclusions and future aspects

The AIP case is a clear candidate for DC-system implementation based on the relatively high energy throughput and substantial cost and energy savings due to higher overall efficiency; the case is OPEX driven. Here, notable operational emissions can be reduced by employing a higher efficiency charging infrastructure, but which is fading in the shadow of the much larger impact of electrifying the heavy transports.

One challenge for AIP case will be definitive location of DC-system(s) with the large area to cover. Here, it can be wise to centralize around the two areas given in the result section above, and overview how the legacy AC infrastructure is at the other areas to allow for a few chargers also at those positions without investments in new grid connections.

In the next project phase, further involvement of especially the operators of on-site-vehicles as well as the logistics firms supplying the heavy transportation would be a very valuable aspect. Another aspect would be to further consider the organizational aspects regarding operations of charging infrastructure and also review possible public support to cover some of the initial investments.

The Renen parking garage is a less clear-cut case, where the overall financial sheet is being CAPEX driven due to relatively lower consumption, efficiency gains have smaller impact. The selection in this case is much a question of future outlook and expectations regarding:

1. How the increase of EV clients plays out within the system lifetime
2. How the system is envisioned to be design in 4D – i.e. accounting for changes over time, with expansion, fast charging capabilities etc.
3. How energy prices develop
4. If batteries are to be implemented as boosters
5. If V2G functionalities are envisioned

With the current trend on increasing consumption seen between scenario 1 and 2, it is quite viable to motivate the implementation of a DC-grid supporting central inverter for the PV installation, and as such remove some of the costs of the DC-system. However, the costs here are in large portion associated with the DC-grid and DC-charging units themselves; even though the higher use case scenario sees a 30% decrease in charging infrastructure lifetime cost per charged unit of energy. Utilizing the same inverter also allows a rationale for having a larger central inverter than is warranted for the initial charging needs, i.e. if the PV array is of higher power, allowing for an easy-to-expand system without overinvesting initially. As the LCOE over the lifetime is similar, within margins of error, for both systems, the DC-system could be attractive, as it scales better with increased loads, that are not accounted for in the base user patterns, but which is expected to change.