Kjernekraft i Norge

innspill til kjernekraftutvalget

Jan Emblemsvåg

Innhold

NB! Noen artikler av undertegnede er lagt ved for å korte ned innspillet, men de bør leses. Andre artikler er bare referert til i innspillet på lik linje med andre kilder.

Undertegnede har valg å fokusere på elementer som kan være interessante.

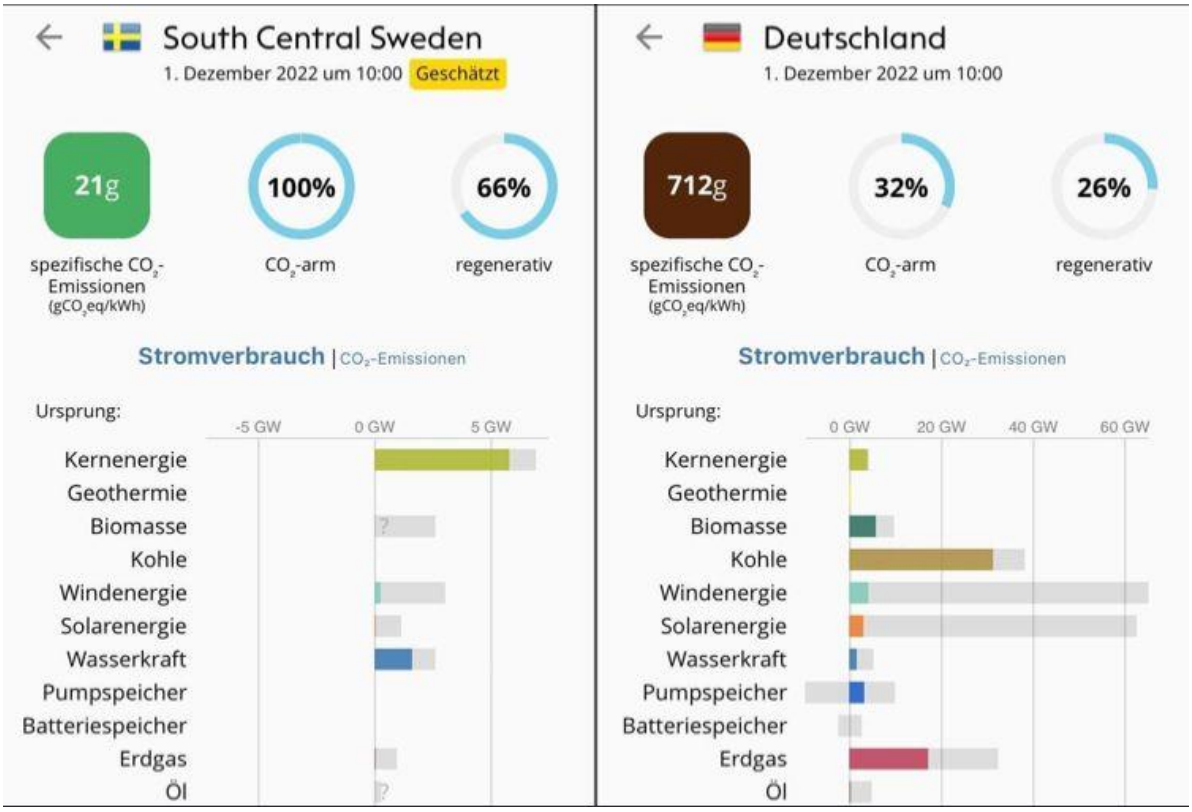
Ålesund, 2025-06-24

1.0 Introduksjon

Det er viktig å holde klart for seg hva som er målene ved energiomstillingen. Målet er et lav-karbon energisystem, som kan defineres i tråd med EU sine krav til å være et energisystem med maksimalt 100 gram per MWh utslipp av klimagasser gjennom hele livsløpet. Hvis ikke overføres utslipp fra et sted på jorden til et annet sted uten at det gagner klimaet.

Per dags dato er det kun to energikilder som ligger innenfor dette kravet – vannkraft og kjernekraft. Det skyldes at sol- og vindkraft trenger balansering av nettverkstekniske årsaker (Emblemsvåg 2022a). Jo mer vind og sol man bygger ut, jo mer gass/kull bruker man til balansering (Devlin *et al.* 2017; Emblemsvåg 2021a). Grunnen til at Danmark og enkelte andre land kan påberope seg høyere andel vindkraft til tider er at kraftsystemet synkroniseres fra nabosystemene. Uten dem ville Danmark kollapset. Denne begrensingen ved sol- og vindkraft er enda ikke løst.

Realitetene vises godt i Figur 1 der vi ser et øyeblikksbilde fra sør-midt Sverige og Tyskland. Her ser vi hvordan sol- og vindkraften i Tyskland nesten ikke har produksjon slik at i praksis er det fossile energikilder som holder systemet gående. Resultatet er svært høye klimagassutslipp. Sverige derimot har svært gode klimagassutslipp ved hjelp av kjernekraft og vannkraft.

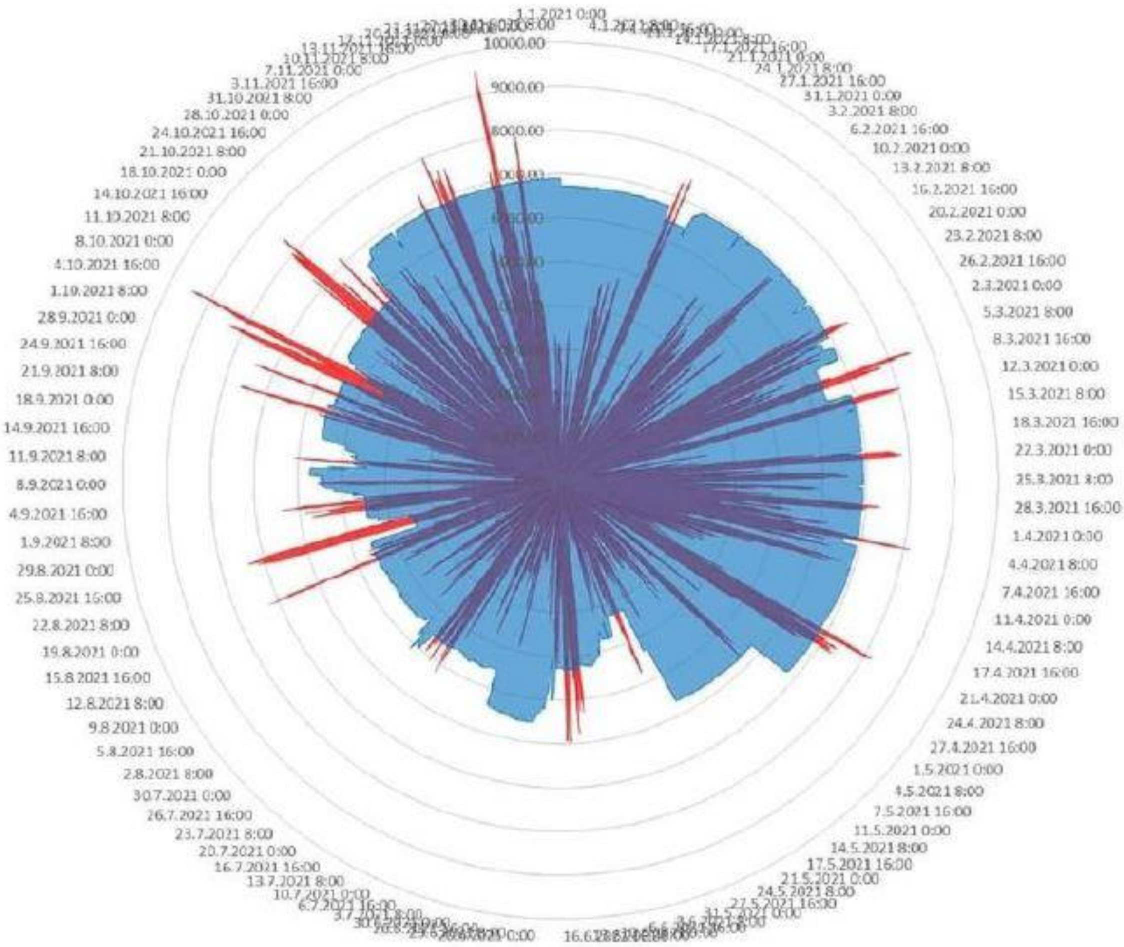


Figur 1 – Sør-midt Sverige kontra Tyskland 2022-12-01. Kilde: https://app.electricitymaps.com/map.

Ser man videre på det svenske systemet vil man se at vindkraften i veldig liten grad bidrar til stabil kraftforsyning, se Figur 2. Dette ser vi overalt med mye variabelt energitilfang. Det finnes ingen industrianlegg på nevneverdig skala globalt, som kan bruke variabel kraft som vind- og solkraft[1].

[1] Se vedlagt artikkel; Emblemsvåg, Jan. (2023) Powering large industrial facilities – using wind- or nuclear power? International Journal of Sustainable Energy. doi.org/10.1080/14786451.2023.2260008.

I den grad slik kraft skal inn i miksen, blir fort kostnadene høye for industrianlegg med mindre de sikrer seg i det finansielle kraftmarkedet og sender regningen til forbrukerne.



Figur 2 – Svensk kraftproduksjon i 2021. Det blå er kjernekraft mens det røde er vindkraft.
Data er fra www.svk.se.

Variabel kraft gir også sterkt volatile priser. I 2021, for eksempel, varierte sluttkundeprisene fra lett negative til helt opp i 24 kr/kWh i UK. UK har betalt opptil £9.724,54/MWh (ca 120 kr/kWh) for å få elektrisitet fra Belgia (Blas 2022), og vindkraften falt fra 16,4 GW til 0,4 GW på kun 40 timer (Stuttaford 2022).

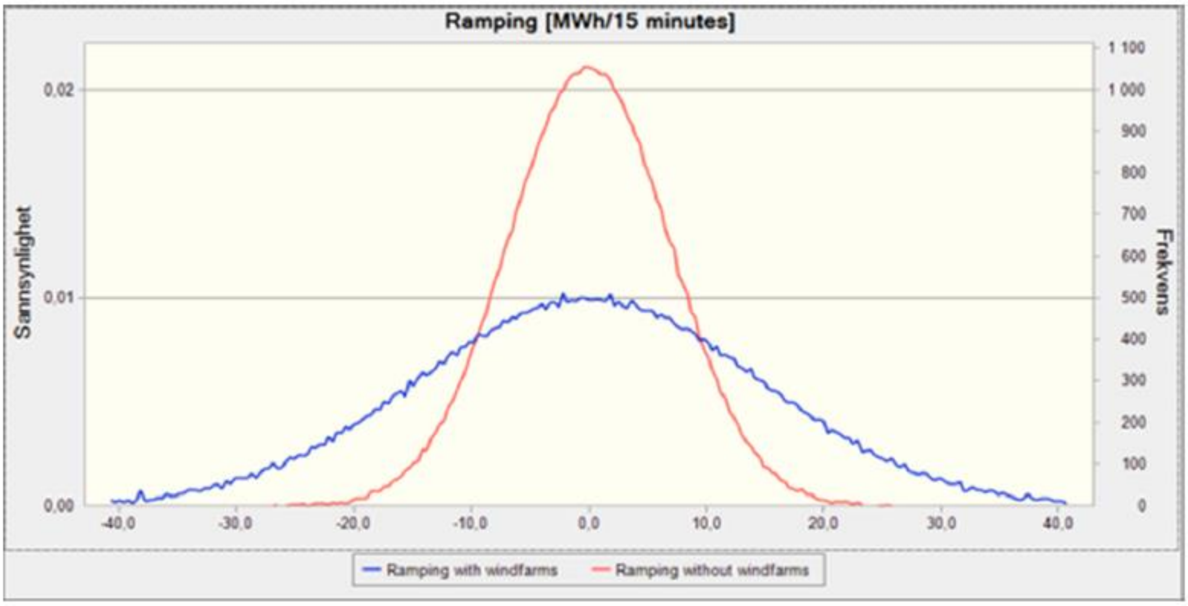
Det å beregne fastpriskontrakter, som kunder kan kjøpe i det finansielle kraftmarkedet, blir da ekstremt risikabelt for tilbyder. Det er ikke uten grunn til at det ble i medio 2022 anslått at det europeiske finansielle kraftmarkedet måtte tilføres likviditet i størrelsesorden 1500 mrd euro (Twidale and Buli 2022)! Hovedgrunnen til denne situasjonen er selvsagt Russlands invasjon men problemene begynte lenge før, og er drevet primært på sikt av underinvesteringer innen olje- og gassindustrien (Holter and Ånestad 2022). Investeringene er 56% lavere i 2021 enn i 2014, og den europeiske (eks. Russland) olje- og gassproduksjonen er 15% lavere (Hares and Yilmaz 2022).

Volatiliteten har også rent tekniske implikasjoner som direkte påvirker hovedformålet – det å redusere utslippene. I Figur 3 ser vi konsekvensene av introduksjonen av vindkraft i Irland. Som vi ser er opp/ned rampingen på 15 minutter intervall uten vindkraft (for å svare på etterspørselsendringer) omtrent ±20 MWh/15 min, men når vindkraften ble introdusert har dette nå i utgangen av 2019 ført til en dobling til ±40 MWh/15 min.

Man har også måttet øke kraftsystemreservene (turbiner som spinner, men som kobles inn og ut på minuttnivå for å svare på etterspørselsendringer) med 10% per 1 GW økning i installert vindkrafteffekt i Irland (Doherty and O'Malley 2005).

Volatiliteten sliter mye mer på utstyret, forkorter levetiden (O'Halloran 2021a), etc. Faktisk, et gasskraftverk gikk ned pga slitasjen (O'Halloran 2021b). Slik rovdrift på utstyr og system påvirker utslippsprofilene mye og koster selvsagt penger. Faktisk har Irland, som det selvstendige kraftnettet i verden med høyest penetrasjon av vindkraft, kun klart å redusere sine livsløps karbonutslipp med kun 10 – 20% (Emblemsvåg 2021a). De er derfor langt unna et lav-karbon krav.

Volatiliteten i kraftsystemet har derfor konkrete finansielle og miljømessige konsekvenser og dessverre går alle i negativ retning.



Figur 3 – Ramping med eller uten vindkraft. Kilde: (Emblemsvåg 2021a).

Et annet element som må tas med i diskusjonen er materialbruken. I Figur 4 ser vi materialbehovene per TWh produsert for ulike kraftkilder. Vi ser at solkraft og vindkraft er spesielt krevende pga det grønne innslaget. Det er beskrevet som 'Other, med det utgjør i praksis det vi kaller sjeldne metaller og -jordarter (Rare Earth Elements (REE)) samt noen kritiske andre metaller og mineraler.

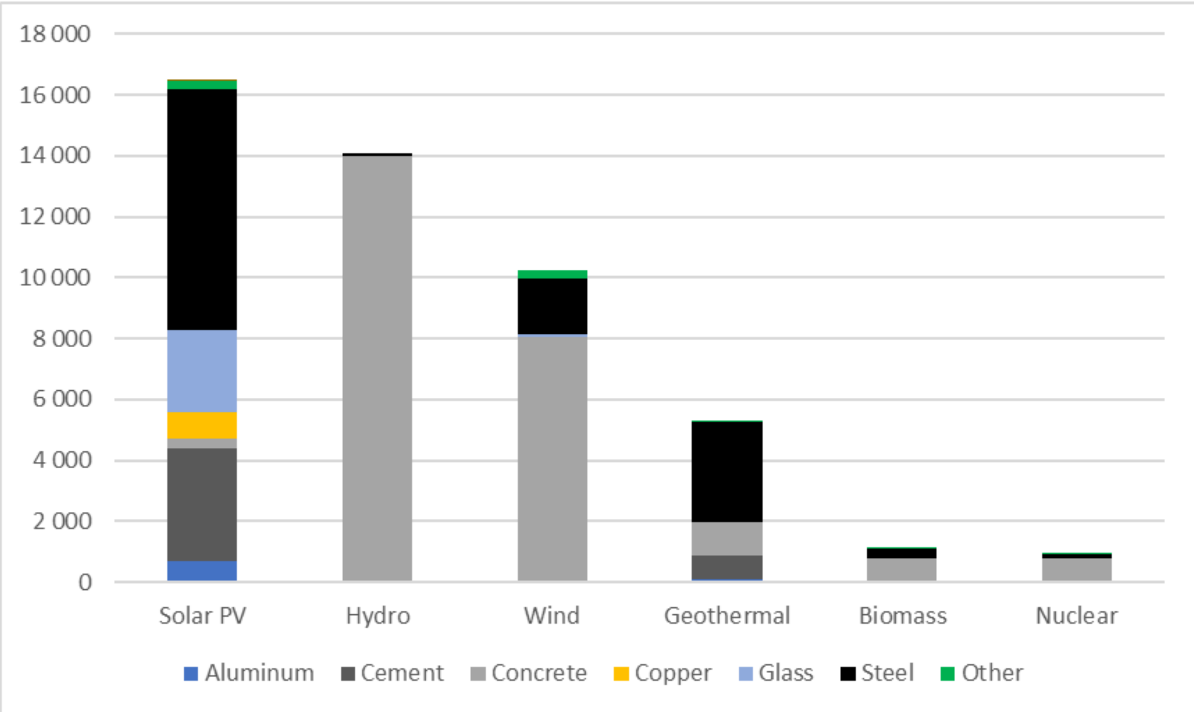
Situasjonen rundt REE er også energisikkerhet. Når vi ser hva Russland kan forårsake av problemer som hadde kanskje 30-40% av EU gassmarkedet, så kan vi begynne å lure hva en stormakt med 95% av prosesseringskapasiteten av all REE og kritiske- metaller og mineraler kan gjøre. Denne makten, Kina, har i dag med andre ord nærmest monopol på prosesseringen, og de har ca 70% av gruvekapasiteten (Vagneur-Jones and Padilla 2023). Dette er en del av en større strategi (Nivelle 2023). Dessverre har Vesten satt seg i en usedvanlig dårlig posisjon der Europa i dag vil faktisk ikke være i stand til å flytte tilbake mye av den industrien som er flagget ut pga energibalansen. Videre vil det kreve en endring i folkeopinionen fordi slik prosessering er potensielt veldig forurensende lokalt.

Når det gjelder sol- og vindkraft er situasjonen krevende. Mens 20% av de truede dyreartene er truet av klimaendringer, er hele 80% truet av habitattap og ødeleggelser (Maxwell *et al.* 2016) der en stor bidragsyter er gruvedrift vedrørende uthenting av REE (Sonter *et al.* 2020). Vi ser generelt fotavtrykket for ikke-fossile energikilder i Figur 4. Som vi ser er uttaket fra naturen stort for de fleste energikilder bortsett fra kjernekraft.

Videre estimerer (IEA 2021) at gruvedrift må økes med inntil 20-40 ganger og overføringsnett for kraft må verden bygge ut og oppgradere over 80 millioner kilometer kraftnett innen, som tilsvarer hele dagens globale kraftnett (IEA 2023). Dette vil forverre materialsituasjonen ytterligere og selvsagt naturødeleggelsene.

En annet forhold som begynner å få mer oppmerksomhet er de forferdelige forholdene som rår ved uthenting av kritiske materialer, slik som gruvene i Kongo ift Kobolt der titusener av barnearbeidere inngår og bruk av slavearbeid i Kina ifm utvinning av REE. Ikke bare er dette etisk forkastelig, men (UNSCEAR 2016) skriver rett ut at en arbeider i denne industrien får i gjennomsnitt 40 – 80 ganger større strålingsdoser enn arbeidere i urangruver.

Kjernekraft ligger på andre enden av Figur 4, og denne kraftkilden er stort sett stål og betong med et innslag av uran, se Seksjon 3. Denne store forskjellen i materialbehov ser vi også i miljøvirkningene, som er godt dokumentert av EU. Undertegnede regner med at EUs LCA analyse er kjent for utvalget.



Figur 4 – Materialbehov [tonn/TWh] for ulike energikilder. Datakilde: (US DOE 2015).

Til slutt er det viktig å legge vekt på at elektrisitet er faktisk den enkle delen av energiomstillingen noe subsidiene av elbiler i Norge viser ift det labre resultatet. Elektrisitet utgjør i Norge ca 45% av primærenergien, pluss/minus noen prosentpoeng avhengig av hvordan det blir beregnet.

To vedlagte artikler[2] viser utfordringene globalt og lokalt i Norge ift grønne alternative drivstoff. Slike drivstoff vil ikke blir tilgjengelige pga det store energitapet i energisystemet med produksjon og bruk. Selv bare den lokale flåten av skip i Norge vil kreve over 30 TWh i elektrisitet for å

[2] 1) Emblemsvåg, Jan. (2025) A Study on the Limitations of Green Alternative Fuels in Global Shipping in the Foreseeable Future. Journal of Marine Science and Engineering (JMSE). doi.org/10.3390/jmse13010079.
2) Emblemsvåg, Jan. (2025) Fremtiden til grønne, maritime drivstoff i Norge – en energianalyse. Naturen. doi.org/10.18261/naturen.149.1.4.

dekarbonisere lokal skipsfart, mens den norske utenriksflåten vil kreve flere hundre TWh. Så kommer fly i tillegg med like dårlige tall.

Derfor vil man aldri komme utenom kjernekraft om man skal overholde alle avtalene som er signert – heller ikke i Norge. I dette innspillet er det dog ikke lagt slike store ambisjonsnivåer. Det er utelukkende tatt utgangpunkt i å evaluere kjernekraft for Norge uten å ta stilling til alternativene. Det er selvsagt metodisk feil ift opsjonsteori, men skal man følge resonnementet over er det egentlig bare ett relevant spørsmål for Norge igjen – HVORDAN skal Norge begynne med kjernekraft og ikke OM Norge skal begynne med kjernekraft.

Dette innspillet vil derfor bare se på noen av nøkkelforholdene rundt kjernekraft som er uavhengig av opsjonsbildet, og de er:

1) Valg av reaktorteknologi.
2) Tilgang på brensel.
3) Lagring av nukleært avfall.
4) Kostnader og finansiering.

2.0 Valg av reaktorteknologi

Valg av reaktorteknologi er svært viktig og herunder også leverandør. I Figur 5 ser vi de store forskjellene mellom ulike lettvannsreaktor (LWR) teknologier, land hvor de er bygget og leverandører. Det gir store utslag på Levelized Cost of Energy (LCOE), som diskutert i Seksjon 5.

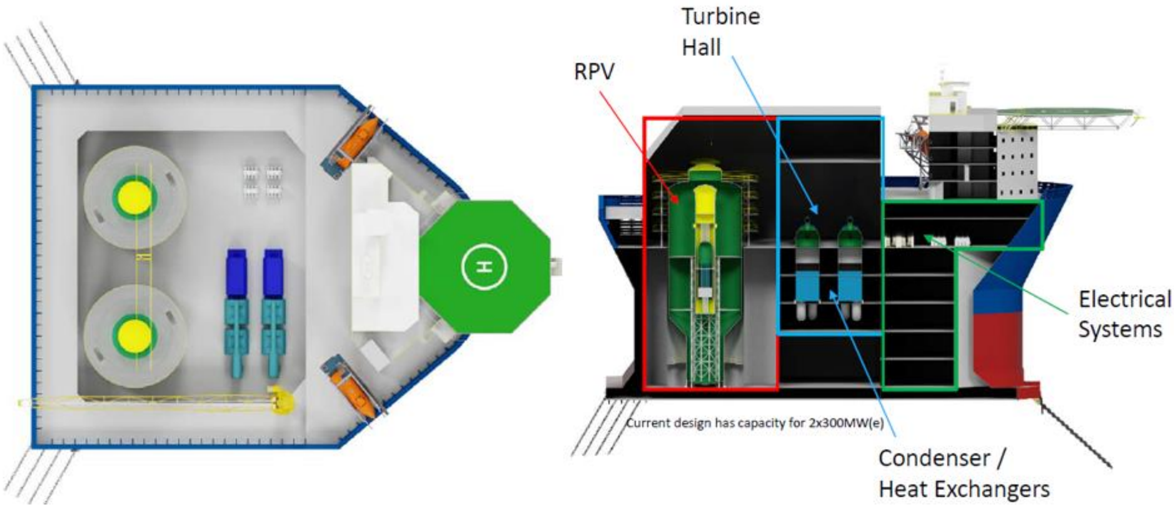
Country	Technology with 60 year life times	Size	Refurbishment and D&D costs			Fuel and waste costs	O&M costs	LCOE			
			3%	7%	10%			3%	5%	7%	10%
		MWe	USD/MWh			$/MWh	$/MWh	USD/MWh			
Belgium	Gen III	1 000-1 600	0.46	0.08	0.02	10.46	13.55	51.45	66.13	84.17	116.81
Finland	EPR	1 600	0.44	0.06	0.01	5.09	14.59	48.01	66.52	81.83	115.57
France	EPR (2030)	1 630	0.40	0.06	0.01	9.33	13.33	49.98	64.63	82.64	115.21
Hungary	AES-2006	1 180	1.59	0.26	0.06	9.60	10.40	53.90	70.08	89.94	124.95
Japan	ALWR	1 152	0.42	0.07	0.02	14.15	27.43	62.63	73.80	87.57	112.50
Korea	APR 1400	1 343	0.00	0.00	0.00	8.58	9.65	28.63	34.05	40.42	51.37
Slovakia	VVER 440	535	4.65	1.50	0.83	12.43	10.17	53.90	66.68	83.95	116.48
UK	Multiple PWRs	3 300	0.54	0.09	0.02	11.31	20.93	64.38	80.88	100.75	135.72
US	ABWR	1 400	1.26	0.52	0.26	11.33	11.00	54.34	64.81	77.71	101.76
Non-OECD members											
China	AP 1000	1 250	0.23	0.04	0.01	9.33	7.32	30.77	34.57	47.61	64.40
	CPR 1000	1 080	0.16	0.03	0.01	9.33	6.50	25.59	33.05	37.23	48.83

Figur 5 – Kostnader (USD 2016) ved bygging av tradisjonell kjernekraft. Kilde: The Full Costs of Electricity. Provision Nuclear Energy Agency International Workshop 2016, OECD, Paris.

Dessverre er den en rekke folk i Norge som snakker om kjernekraft som en monolittisk ting, men det er det absolutt ikke hverken teknisk eller økonomisk eller praktisk. Hvis Norge skal vurdere kjernekraft bør det legges til grunn en del faktorer som sikrer god prosjektgjennomføring og lave kostnader. Som vi ser fra Figur 5, så kan Sør-Korea sine saker svært godt. De utvikler standardløsninger, de kan å bygge effektivt og kanskje aller viktigst – de har riktig måte å tenke på.

Den samme situasjonen ser vi innen Små- og Mikro Modulære Reaktorer (SMMR). Der har vi ved NTNU kjøre en seleksjonsprosess der alle 80+ teknologiene i verden er vurdert for bruk på skip og industrianlegg. Tilsvarende seleksjonsprosess bør kjøres av Norge om man ønsker å gå videre for å finne beste løsningen[3], men selvsagt med noen andre kriterier som er mer egnet for landbasert kjernekraft.

Når det er sagt, er det viktig å legge til at et flytende anlegg kan være en svært god løsning. De er enklere å bygge, vanskeligere å ramme ift jordskjelv og tsunamier, enklere å dekommisjonere og ved ekstreme hendelser kan de lettere sikres. Det eneste som er bedre er et anlegg bygget dypt inn i fjell. Denne teknologien har vi i Norge allerede, og i Figur 6 er det vist et anlegg på ca 600 MW (elektrisk effekt).



Figur 6 – Flytende kjernekraftanlegg. Design: CeFront.

3.0 Tilgang til brensel

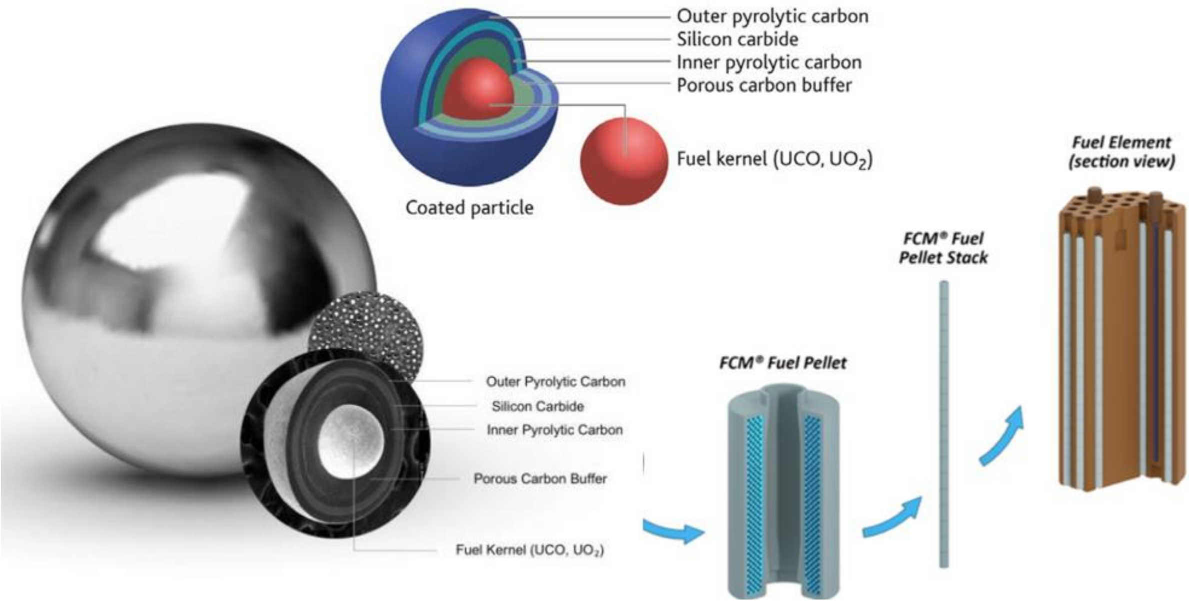
Det fleste kjenner til mengden uran på land, som i seg selv er anselig, men det er mye mer ukjent at det finnes enorme mengder i havet (ca 4,6 mrd tonn) som fornyes fra jorden indre (Hollenbach and Herndon 2001), og vil om få år kunne hentes ut derifra kommersielt (Bauer 2018). I mellomtiden har Australia og Canada de største mengdene på landjorden. Med de moderne reaktorene som utvikles vil kjernekraft faktisk gi nok energi til hele menneskeheten i inntil 4 mrd år. Ingen annen kraftkilde har det potensialet.

Noe annet som er verdt å nevne er utviklingen innen selve brenselsteknologien. I Figur 7, ser vi Tri-Isotropisk (TRISO) brensel, som det amerikanske energidepartementet kort og godt kaller verdens mest robuste brensel[4]. Det tåler ca 2000 grader Celsius over kortere tid og 1600 grader Celsius over lang tid, og det tåler over 10.000 år i saltvann. Videre er det umulig for ikke-statlige aktører å få ut innholdet, og det forenkler lagringen veldig.

Kostnadene vi ser i NuProShip prosjektet undertegnede leder, er omtrent 40% billigere enn tungolje per MWh levert energi. Dette er selvsagt et brensel som kan benyttes på land om man vil. Da har man lagt til enda et sikkerhetslag på anlegget.

[3] Seleksjonsprosessen er diskutert i vedlagt artikkel: 10. Emblemsvåg, Jan; Ordoñez, César Hueso; Tamm, Cristian Garrido; Strand, Terje; Thoresen, Helge; Ortigosa, Javier Santos. (2024) Criteria for selecting nuclear reactor for merchant shipping. ASME International Conference on Nuclear Engineering ICONE 31, Prague 2024-08-04 - 2024-08-09.

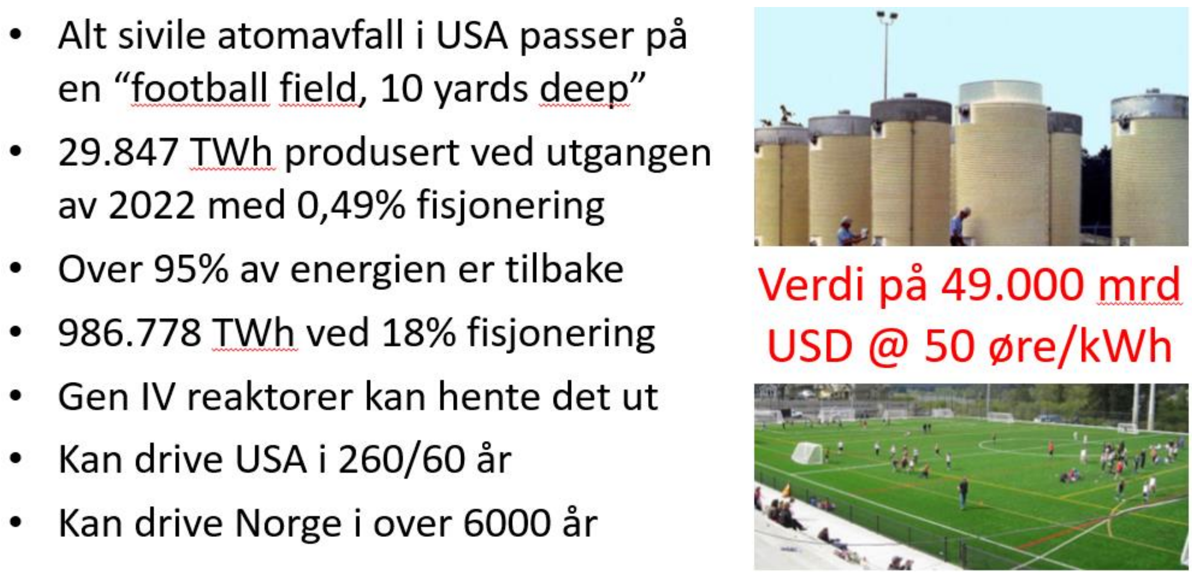
[4] Se https://www.energy.gov/ne/articles/triso-particles-most-robust-nuclear-fuel-earth



Figur 7 – TRISO brensel i ulike versjoner.

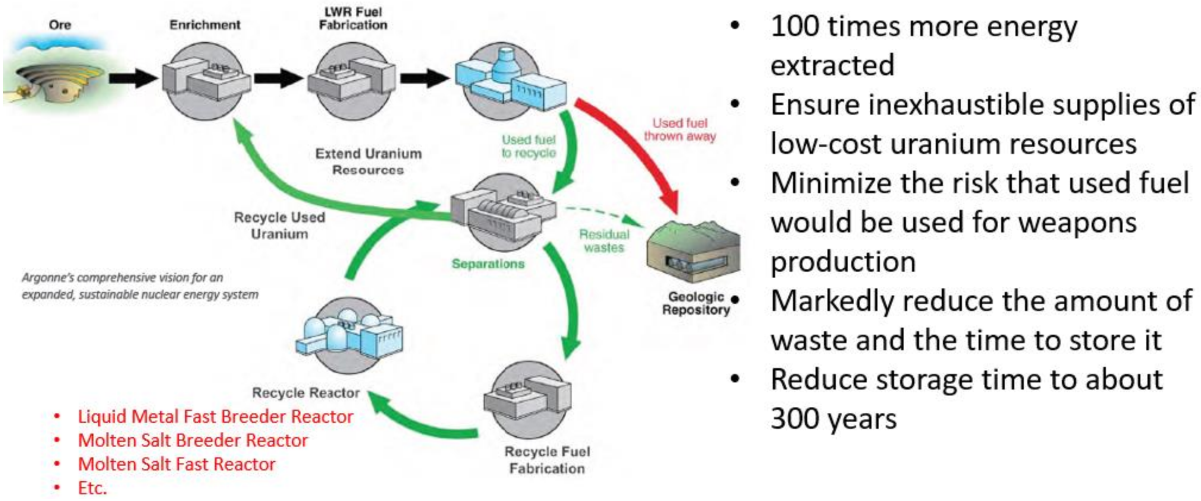
4.0 Lagring av nukleært avfall

Nukleært avfall er ikke avfall i normal forstand. Man har selvsagt lavradioaktivt avfall, som er avfall, men når man snakker om radioaktivt avfall forstår de fleste det som egentlig brukt brensel. I Figur 8 har jeg leget et sammendrag av situasjonen i USA. 0,49% fisjonering er fisjoneringen ved en vanlig LWR, mens 18% fisjonering er fisjoneringen på en avansert reaktor under utvikling. Som vi ser, inneholder så kallet radioaktivt avfall ekstremt mye uutnyttet energi. Kostnadene med å lagre dette er trivielle ift verdien spesielt om man bruker det senere i Generasjon IV reaktorer med høy fisjoneringsgrad.



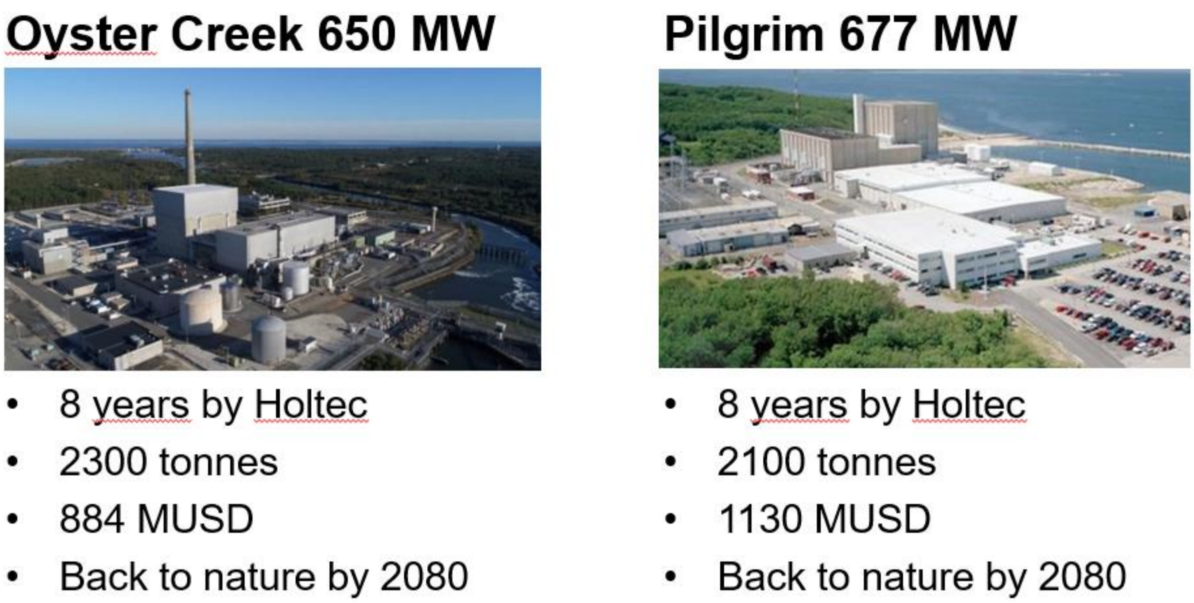
Figur 8 – Fakta om brukte brensel.

Man kan også resirkulere brukt brensel, som vist i Figur 9. Det vil dramatisk øke energimengden man kan hente ut og lagringstiden.



Figur 9 – Resirkulering av brensel. Kilde: ANL (2018). Pyroprocessing Technologies: Recycling used Nuclear Fuel for a Sustainable Energy Future. Lemont, IL, US Department of Energy, Argonne National Laboratory (ANL) https://www.anl.gov/sites/www/files/2018-2010/Pyroprocessing_brochure_2018.pdf.

Til slutt er det viktig å være klar over at lagring i seg selv langt fra er vanskelig. Finland har allerede bygget dypt geologisk lager. Det samme gjelder dekommisjonering, som vist i Figur 10. Der ser vi nøkkeltallene for to anlegg i USA under dekommisjonering.



Figur 10 – Dekommisjonering av anlegg i USA som er snart ferdig etter plan og budsjett. Mer informasjon kan hentes hos det amerikanske strålevernet (US NRC).

Dekommisjonering av en rekke gamle anlegg er mye vanskeligere pga dårlig dokumentasjon og vanskelige isotoper generert under forsøk. Dette har dog ingenting med kommersiell kjernekraft å gjøre.

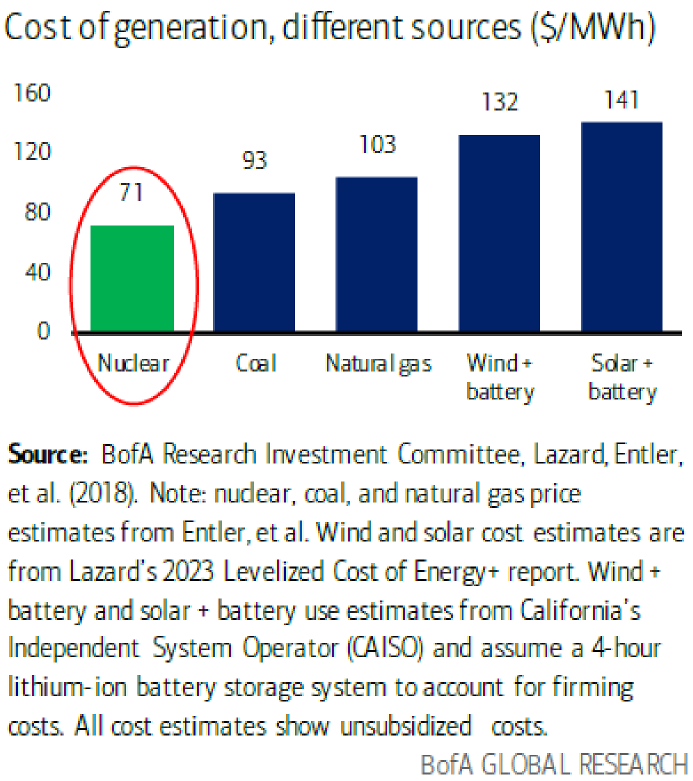
5.0 Kostnader og finansiering

Både i den offentlige debatten og hos folk som burde vite bedre, finner man mye feil når det gjelder kostnadene ved kjernekraft. Det er spesielt to forhold det syndes mot, som forklart grundig i vedlagt artikkel[5]:

1) Feil finanskostnader ift levetid.
2) Manglende krav til energikildene slik at man sammenligner epler mot pærer.

Det er også en rekke andre forhold, men som gir numerisk mindre påvirkning på analyses.

Bank of America har faktisk gjennomført et studium der de ser på LCOE ved en rekke energikilder og de har forsøkt å tilskrive totale kostnader – dvs, anleggskostnadene pluss de tilhørende systemkostnadene energikilden forvolder (Woodard *et al.* 2023). Noen av resultatene er vist i Figurene 11-13. Tallene i Figur 11 er regnet ut som i (Emblemsvåg 2021b, 2022b) bare at de har tatt mindre batterikrav, mens (Emblemsvåg 2021b, 2022b) satte et 100% pålitelighetskrav som gjorde at kostnadene ble enda høyere, for eksempel, 250 USD/MWh for solkraft.

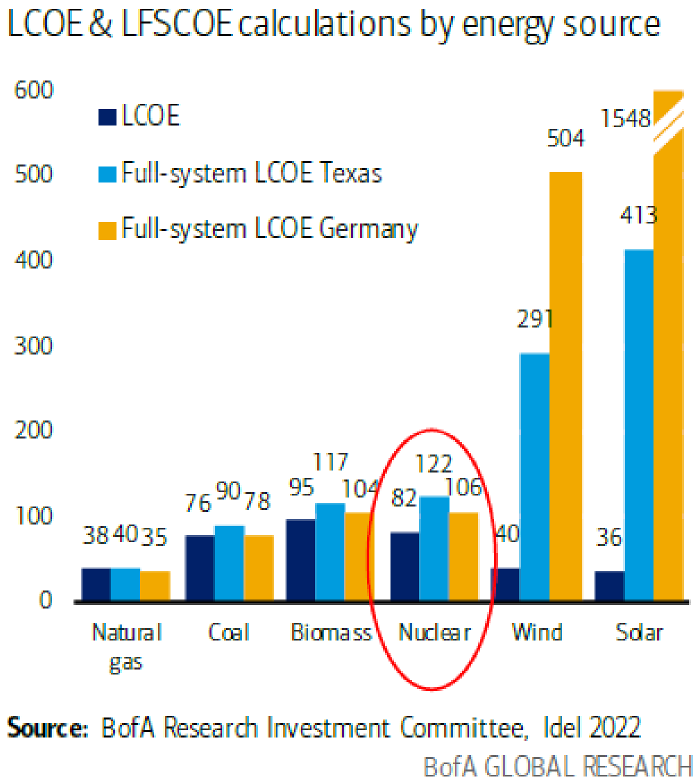


Figur 11 – Produksjonskostnader ved ulike energikilder når man har satt visse pålitelighetskrav, som medfører bruk av batterier for sol- og vindkraft. Kilde: (Woodard *et al.* 2023).

I Figur 12, ser vi LCOE resultatene med og uten systemkostnadene der Bank of America har regnet på Tyskland og Texas. Tallene taler for seg. Når alle kostnader er tatt med vil vindkraften koste 3 og 5 kr/kWh i Texas or Tyskland, respektivt. Solkraften vil koste hele 4 og 15 kr/kWh i Texas og Tyskland, respektivt. Disse resultatene forklarer hvorfor man i alle land med stor andel av fornybarenergi opplever svært høye elektrisitetspriser.

[5] Emblemsvåg, Jan. (2025) Rethinking the "Levelized Cost of Energy": A critical review and evaluation of the concept. Energy Research & Social Science. doi.org/10.1016/j.erss.2024.103897.

Den siste figuren, Figur 13, viser Energy Return on Investment (EROI) som er forholdet mellom den mengde energi man får fra en energikilde gjennom livsløpet og den mengde energi man har brukt på å fremskaffe energikilden gjennom hele livsløpet. Vi ser her at kjernekraft gir 75 ganger mer energi enn det som har blitt brukt på å fremskaffe denne energien. Vi ser også at forfatterne har tegnet inn grensen for dagens sivilisasjon ved 7. De energikildene som ligger under denne grensen, ville medføre økonomisk kollaps og samfunnskollaps deretter om det var kun disse energikildene samfunnet hadde. Vi ser av resultatene at fornybarenergi ikke er hverken økonomisk fornuftig eller ut i fra et EROI perspektiv.

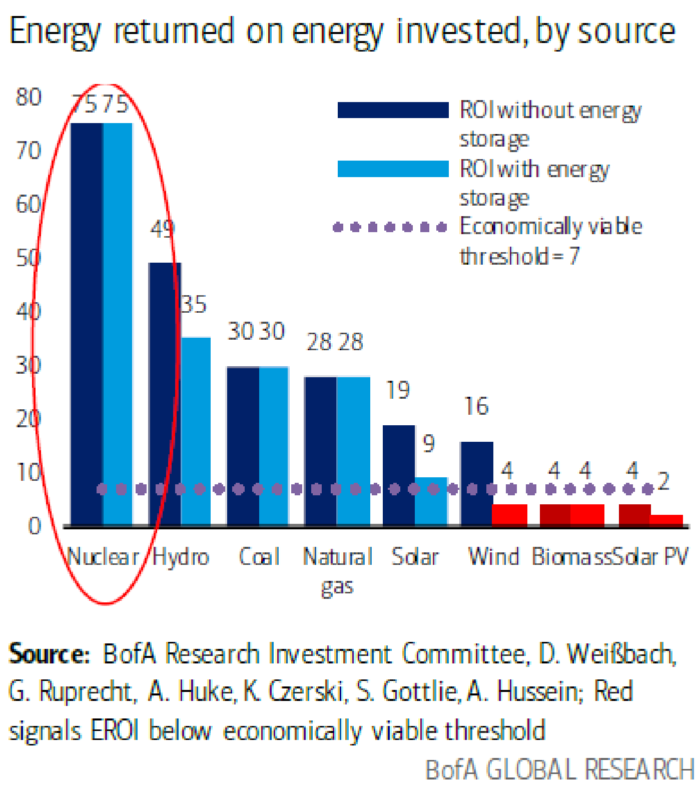


Figur 12 – LCOE med og uten totale systemkostnader for ulike energikilder. Kilde: (Woodard *et al.* 2023).

Vi kan finne gode eksempler på kjernekraft, og Emiratene fremheves av IAEA som et godt eksempel (Madsen 2021). Emiratene, som aldri har hatt noe med kjernekraft å gjøre før, har sammen med KEPCO bygget 4 stk APR1400 kjernekraftverk på 11-12 år med en årsproduksjon på 45 TWh og med en levetid på over 65 år. Det er omtrent fire ganger mer enn all vindkraft i Norge bygget over 20 år med en levetid på kun 20 år. Kostnaden til Emiratene er omtrent 300 mrd kroner, mens Pareto estimerer at det vil koste 420 mrd kroner å løse energi-gapet på 40 TWh/år identifisert av Energikommisjonen i Norge (Hovland 2023). Kjernekraft bygges altså mye fortere og billigere når totalbildet er inkludert.

Andre bygger kullkraft først for så å kunne konvertere dem. Dette er en strategi flere mener Kina følger. USA har derfor gjennomført et svært interessant studium. Dersom de erstatter dagens kullkraft med kjernekraft – altså bokstavelig talt bare bytter ut kullkjelene med reaktorer – vil de spare 15 – 35% av investeringene fordi man kan benytte dagens infrastruktur og dampturbiner og mer (Hansen *et al.* 2022). Man vil videre øke kapasiteten med ca 260 GW fordel på 315 anlegg og derved øke produksjonen med utslippsfri kraft med hele 2100 TWh/år. Dersom disse kjernekraftanleggene bruker restenergien til produksjon av syntetisk drivstoff – slik som grønn ammoniakk – vil de i tillegg kunne produsere nærmere 200 millioner tonn.

I 2021 ble 4.108 TWh elektrisitet produsert i USA hvorav 61% var fossil (2.508 TWh), 19% var kjernekraft (778 TWh), 9% (378 TWh) var vindkraft, 6% (252 TWh) var vannkraft, 3% var solkraft (115 TWh), 1% var biomasse (54 TWh) og resten er ymse. Denne planen vil da medføre at USA får en 90% fossilfri kraftforsyning som er blant de beste i verden.



Figur 13 – Energy Return on Investment (EROI) for ulike energikilder. Kilde: (Woodard *et al.* 2023).

Det viktigste dog med kostnader og finansiering er at man må være konkret og analysere det riktig, som diskutert i vedlagt artikkel om LCOE. Generiske analyser gir noe innsikt, men kan like gjerne villede som å veilede. Et godt eksempel er den berømte rapporten til Rystad. Her[6] er min analyse av den, som kjernekraftutvalget bør lese som en del av dette innspillet.

6.0 Noen kommentarer til slutt

Dette var et innspill der undertegnede prøvde å unngå for mye detaljer generelt men mer der undertegnede tror det kan ha mest nytte. Uansett hva dere kommer frem til er det viktig å sette veldig klare forutsetninger for arbeidet og rapporten og så diskutere de til slutt i rapporten.

Hovedutfordringen til kjernekraft i vestlige land har vært, og er, politikken. Når Kina har 44 anlegg under bygging, og vi vet KI vil kreve kanskje 10-20 ganger mer energi enn vanlige datasentre, så betyr det kort og godt at fremtiden tilhører de med nok, stabil kraft. Det var konklusjonen til CEO til OpenAI, Sam Altman[7].

[6] https://ksu.no/artikler/kronikk/122619-kjernekraft-i-norge-nodvendighet-som-trenger-politiske-visjoner-og-en-faktabasert-debatt

[7] Se for eksempel https://www.windowscentral.com/software-apps/sam-altman-openai-needs-significant-fraction-of-earth-power

Siden energisystemer tar tid å bygge er det derfor viktig at man ser langt nok frem og tenker stort nok, ellers vil vi aldri klare å henge med i den utviklingen Altman og andre ser for seg. OM det blir riktig, er umulig å vite, men hva om det blir slik?

Datasentre krever 99.999% pålitelighet, og Google, Meta, Microsoft, Amazon m.m. har signert avtaler med kjernekraftanlegg. Kairos Power i NuProShip prosjektet, skal levere sin første reaktor på 75 MW i 2030 til Google. Det er en saltsmeltereaktor med TRISO brensel. Så langt frem er altså Generasjon IV... Mye nærmere enn de fleste vet.

Dere har et stort ansvar på vegne av Norge. Lykke til.

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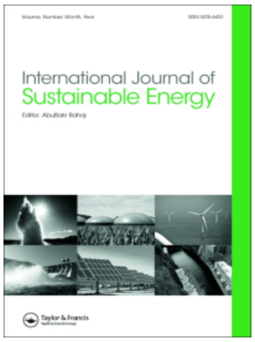

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International Journal of Sustainable Energy

ISSN: (Print) (Online) Journal homepage: https://www.tandfonline.com/loi/gsol20

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To cite this article: Jan Emblemsvåg (2023) Powering large industrial facilities – using wind- or nuclear power?, International Journal of Sustainable Energy, 42:1, 1241-1263, DOI: 10.1080/14786451.2023.2260008

To link to this article: https://doi.org/10.1080/14786451.2023.2260008

Published online: 26 Sep 2023.

INTERNATIONAL JOURNAL OF SUSTAINABLE ENERGY
2023, VOL. 42, NO. 1, 1241–1263
https://doi.org/10.1080/14786451.2023.2260008

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Powering large industrial facilities – using wind- or nuclear power?

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ABSTRACT

Many industrial facilities require large amount of power available through fossil energy, but in some countries the power is secured by hydroelectric power. Norway is one such country, but some facilities still use gas power due to hydroelectric power capacity limitations. Therefore, using wind- or nuclear power to cut emissions are relevant alternatives. Therefore, a concept and feasibility study using wind- or nuclear power at the single largest emitter of climate gases in Norway, Melkøya LNG (Liquified Natural Gas) terminal is presented. Due to the intermittency of the wind power, the balancing/back-up power must also be included. After running 10,000 trials in a Monte Carlo simulation to handle the uncertainties of the alternatives, the results support the Nuclear alternative. Future key issues are the cost escalations of wind turbines, the cost of balancing- and backup power for the Wind alternative and the waste handling for the Nuclear alternative.

ARTICLE HISTORY
Received 4 September 2023
Accepted 12 September 2023

KEYWORDS
Balancing power; Equinor; levelised cost of energy; Melkøya; nuclear cogeneration

Nomenclature

Capacity	the ability to produce an effect, which in our context is measured in Watt, kW, MW or GW.
CAPEX	Capital expenditures; typically expressed in USD or in specific terms such as MW/USD.
Cogeneration	the capability of producing both electric energy and thermal energy at the same time.
Effect	the instantaneous ability to do work typically measured in Watt (W), kW (thousand W), MW (Million W) or GW (billion W).
Electric energy	energy in the shape of electricity.
Energy	effect produced over time, measured as Joule or in our context here, MWh (Million Watt hours) or kWh (thousand Watt hours). TWh is a million MWh or a thousand GWh.
FOAK	First of a kind; used when describing the prototype version of something concerning costs, construction time, etc.
LCOE	Levelised Cost of Energy; the probability weighted average life-cycle cost normally expressed as USD/MWh.
LNG	Liquified Natural Gas; natural gas that has been liquified through the liquefaction process.
LWR	Light Water Reactor, the most common type of nuclear reactors in operation today.
NOAK	Nth of a kind; used when describing the mature version of something concerning costs, construction time, etc. when much experience has been gathered.
OPEX	Operating expenditures; the expenses used on annual basis to keep something in operations. Typically expressed in the context of this paper as USD/MWh.
Terminal value	the rest value, measured in USD, of an investment at the end of the horizon included in the analysis.
Thermal energy	energy in the shape of heat or fuels (and not electricity). Converting thermal energy to electricity incur losses as dictated by the Second Law of Thermodynamics.

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1. Introduction

Both wind- and nuclear power are today predominantly providing electricity to the power system. Yet, nuclear cogeneration applications have a relatively long history, with nuclear cogeneration recording of over 750 reactor-years of experience in non-electric applications (mainly linked to district heating and desalination) (Rosen 2021). An early example is the Ågesta reactor, south of Stockholm, which produced 10 MW of electricity to the grid and between 50 and 70 MW of heat to the suburb 'Farsta' in Stockholm between 1964 and 1974 (The Royal Society 2020).

In 2020 there were 64 reactors in 10 countries that supplied approximately 3390 GW per hour of electric equivalent heat to support non-electric applications (Goetzke et al. 2022). For example, the Bruce-A nuclear station in Canada consists of four 825-MWe (electric MW) units that are generating electricity. Additionally, the plants supply steam to a transformer plant that generates 720 MWth (thermal MW) of process heat and steam for heavy water production plants; 70 MWth for the Bruce energy centre, and 3 MWth for side services (Barnert, Krett, and Kupitz 1991).

A typical nuclear power station produces around 3.4 GW of heat (~100,000 domestic gas boilers), which is used to generate around 1.2 GW of electricity. Currently, around 65% of the energy is lost in the conversion as waste heat (The Royal Society 2020). Though less than 1% of the heat generated in nuclear reactors worldwide is currently used for district and process heating, there are signs of increasing interest in these applications (Csik and Kupitz 1997). The reasons are twofold. First, the current growth in population worldwide gives increased demand for energy. Second, the need to decarbonise the economy has led governments around the world to seek low-carbon energy sources in line with the Paris Accord of 2015.

For example, in the EU, 26% of total industrial heat demand is for high-temperature heat (>400°C), with the majority generated by burning of fossil fuels (IAEA 2017). In the US, the heat generated by fossil-fuel burning facilities generating 6558 million metric tons of CO_2 emissions would be equivalent to the heat produced by approximately 31,228 Small Modular Reactors (SMR) each rated at 150 MWth. (Goetzke et al. 2022). These numbers say a lot about the decarbonisation challenge and highlight the importance of using energy efficiently. Interestingly, a significant fraction of industrial emissions, roughly 15% divided among petrochemicals, chlor-alkali, paper and pulp, and food processing, can be mitigated through thermal- and electrical integration with a Light Water Reactor (LWR), according to Knighton et al. (2020).

With all the thermal energy wasted by nuclear power stations mentioned above, the immediate question becomes whether or not the rest energy can be used. A district heating system utilising the waste energy from a typical LWR increases the overall efficiency of the power station, depending on heat demand (e.g. season) to over 80% (Partanen 2017). The other possibility to address the two reasons mentioned above is, of course, to use other low-emission energy sources. The purpose of this paper is to evaluate which alternative is overall best for a large industrial plant that has a mix of both electric- and thermal power requirements.

Crucially, the prospects of SMRs as co-generation plants supplying electricity and process heat are considerably better than those of large reactors (Csik and Kupitz 1997). Indeed, the lack of interest of heat from nuclear power has historically given the focus on building large, baseload units (Goetzke et al. 2022). District heating networks generally have installed capacities in the range of 600–1200 MWth[1] in large cities, and the temperature range required by district heating systems is around 100–150°C (Csik and Kupitz 1997), which means that the large nuclear power plants are basically too big. Another issue that favours SMRs is that the annual load factors of district heating systems depend on the length of the cold season when space heating is required, and can reach up to about 50%, which is still way below what is needed for base load operation of plants (Csik and Kupitz 1997).

Another interesting observation is the major differences in nuclear construction costs around the world with the South Korean approach outperforming most other countries. Indeed, according to

Lovering, Yip, and Nordhaus (2016), there is nothing inherent in the technology that predicates the cost escalation seen in some countries since the 80s. This is discussed more in detail in Section 2, but it indicates that how nuclear power projects are performed is critical for the costs and hence the topic of this paper.

Therefore, it is interesting to research whether or not an industrially built SMR will provide power to an industrial facility at lower or higher total cost than wind power. To address this question, we must first review what is known about such applications of nuclear power from before, which is done in Section 3. Then, in Section 4 the Melkøya case in Norway is used as background for a concept and feasibility study followed by critical review of the case in the subsequent section. In Section 6, a more complete approach to reach a final decision is discussed.

2. The costs of power

When it comes to cost estimates, the IPCC and many other organisations rely on 'levelised cost' of various kinds of estimates such as Levelised Cost of Energy (LCOE), Levelised Cost of Conserved Energy (LCCE), Levelised Cost of Conserved Carbon (LCCC) to facilitate a meaningful comparison of economics across diverse options at the technology level (Krey et al. 2014). These cost estimates are essentially weighted average costs with respect to the objective at hand. For example, the LCOE is the weighted average life cycle cost of producing energy from a certain source of energy, as we can see from the standard formula for the LCOE (IRENA 2012):

$$\mathrm{LCOE} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

where LCOE = the average lifetime levelised cost of energy generation. I_t = investment expenditures in the year t. M_t = operations and maintenance expenditures in the year t. F_t = fuel expenditures in the year t. E_t = electricity generation in the year t. r = discount rate. n = economic life of the system.

With the LCOE being used for policymaking worldwide (IRENA 2012), the LCOE is an obvious choice here since we are interested in the technology view and not the investment case *per se*. The difference is that the investment case takes the view of the organisation that invests whereas LCOEs are organisationally independent and take the total view irrespectively of who reaps what benefits and assumes what costs. These two power sources – wind power and nuclear power – are discussed briefly in the two consecutive sections. The purpose is to provide the context for Section 4 and not to present the actual cost estimates *per se* because the cost estimates for the industrial facility are the objective of this paper.

2.1. The cost of nuclear power and cogeneration

The cost of nuclear power varies significantly depending on a number of factors, as shown in Figure 1. The numbers in Figure 1 are a few years old and are therefore only indicative for projects going forward. However, it is a very succinct figure, which is why it is used here. We see, for example, that the South Korean APR 1400 has an estimated LCOE of 34.05 USD/MWh produced given a 5% discounting rate. This is roughly half the cost of just about all the other reactor designs and countries. The question is whether or not these numbers still hold true.

They do hold true because as Lovering, Yip, and Nordhaus (2016) show; there are no intrinsic cost escalations in nuclear power as many authors suggest. The South Korean numbers in Figure 2 are equally interesting. There is a net *decrease* in overnight costs with time. Of course, since overnight costs do not include the financial costs, there can still be an *increase* in the project costs. However, due to the politics often involved in large energy projects, the overnight costs are more

Country	Technology with 60 year life times	Size	Refurbishment and D&D costs			Fuel and waste costs	O&M costs	LCOE			
			3%	7%	10%			3%	5%	7%	10%
		MWe	USD/MWh			$/MWh	$/MWh	USD/MWh			
Belgium	Gen III	1 000-1 600	0.46	0.08	0.02	10.46	13.55	51.45	66.13	84.17	116.81
Finland	EPR	1 600	0.44	0.06	0.01	5.09	14.59	48.01	66.52	81.83	115.57
France	EPR (2030)	1 630	0.40	0.06	0.01	9.33	13.33	49.98	64.63	82.64	115.21
Hungary	AES-2006	1 180	1.59	0.26	0.06	9.60	10.40	53.90	70.08	89.94	124.95
Japan	ALWR	1 152	0.42	0.07	0.02	14.15	27.43	62.63	73.80	87.57	112.50
Korea	APR 1400	1 343	0.00	0.00	0.00	8.58	9.65	28.63	34.05	40.42	51.37
Slovakia	VVER 440	535	4.65	1.50	0.83	12.43	10.17	53.90	66.68	83.95	116.48
UK	Multiple PWRs	3 300	0.54	0.09	0.02	11.31	20.93	64.38	80.88	100.75	135.72
US	ABWR	1 400	1.26	0.52	0.26	11.33	11.00	54.34	64.81	77.71	101.76
Non-OECD members											
China	AP 1000	1 250	0.23	0.04	0.01	9.33	7.32	30.77	34.57	47.61	64.40
	CPR 1000	1 080	0.16	0.03	0.01	9.33	6.50	25.59	33.05	37.23	48.83

Figure 1. The Levelised cost of energy for various reactors designs built in various countries for different cost parameters. Source: (Rothwell 2016).

interesting from a technology point of view and the total costs from a commercial project point of view.

Hence, if done correctly, nuclear power can be very cost effective, and the key is standardisation for large nuclear power plants and industrialisation for SMR, as discussed later in Section 4.4.

This is the reactor part; what about cogenerated power as discussed in this paper? The following rule of thumb can be used: the cost of co-generated heat is equal to the electricity cost divided by the coefficient of plant performance, a factor which depends on the type of reactor under consideration and other parameters[2] (Barnert, Krett, and Kupitz 1991). Using that rule, cost figures for co-generation have been calculated, as an example, for a modular high-temperature gas-cooled reactor

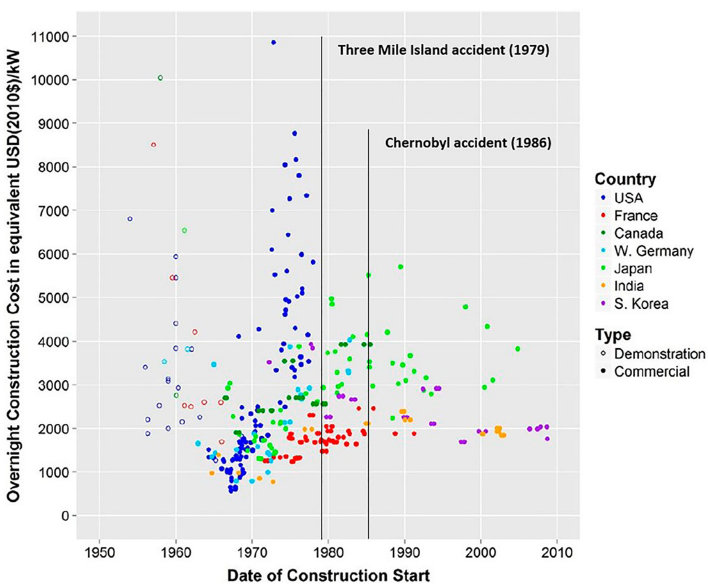

Figure 2. Overnight construction costs for nuclear power plants. Based on (Lovering, Yip, and Nordhaus 2016).

(MHTGR) in Germany where the LCOE over 40 years of electricity equalled 5 US cents per kWh electric, the cost of steam equals 1.7 US cents per kWh(th) and the cost of hot water equals 0.5 US cents per kWh(th) (Barnert, Krett, and Kupitz 1991). An analysis of nuclear cogeneration in Canada, France, UK, USA, and Japan revealed that Canada is cheapest at 29.9 USD/MWh (1991 USD), which is lower than both the cost of coal and gas in all five countries whereas the most expensive is the UK at 55.0 USD/MWh (Hammond 1996).

Recently, the cost of producing high-pressure steam for industrial usage is estimated to be $4.00 to $5.25 per 1000 lb steam, depending on plant type and operation costs. This is 15% to 45% lower than the cost of similar production using a natural-gas package boiler before any credits for carbon emissions are applied (Peakman and Merk 2019).

A challenge with cogeneration is the transport of heat. An analysis performed in the US shows that transport distances up to 6 km are always feasible compared to using gas (Knighton et al. 2020). Of course, the longer the distance, the more thermal losses. Hence, the closer proximity between power production and consumption, the more economical as discussed later.

2.2. The cost of wind power

Since wind power provides direct electricity and no heat, cogeneration is impossible. Here, we must think electrification. The electrification can in itself be highly profitable (Devold, Nestli, and Hurter 2006) provided that the electric power can be supplied at reasonable costs. Due to the reliability target of 100% for industrial users (Csik and Kupitz 1997), it is the cost of the energy delivered to the industrial facility 24/7/365 that counts. Unfortunately, the LCOE estimates for wind power today include the asset level so they are only true on asset level (Emblemsvåg 2024). Hence, a useful cost analysis of wind power for an industrial facility must incorporate all the resources and their costs to secure a 100% reliability target. Thus, it is difficult to say anything generic other than the LCOE for wind power today cannot be used. It is perhaps indicative that Emblemsvåg (2020) finds that the LCOE for wind power using geographical diversification and the US grid average weighted cost for electricity used for balancing and backup power, is 3 times higher than the LCOE for wind on asset level. Therefore, the cost of wind power is discussed in detail in Section 4 where the total system is included.

3. Brief overview of nuclear power for industrial facilities

Three important facts are important to understand when it comes to using nuclear power for industrial facilities. First, the temperature ranges, up to about 300°C are obtained in light- and heavy water reactors, up to 540°C in liquid metal-cooled fast reactors, up to 650°C in advanced gas-cooled reactors, and up to about 1000°C in high-temperature gas-cooled reactors (Csik and Kupitz 1997). However, the current industrial heat demands for temperature in the range of 500–1000°C are relatively low (Peakman and Merk 2019).

Up to about 550°C, the heat can be supplied by steam; above that, requirements must be served directly by process heat. However, for nuclear technology the current upper limit is 1000°C set on the basis of the long-term strength of metallic reactor materials (Barnert, Krett, and Kupitz 1991). Above 1000°C, nuclear power can only contribute indirectly through, e.g. electricity.

The exact mix of thermal versus electric energy will depend on different countries' industrial base and their requirements. For example, if we investigate the UK requirements, the two lowest temperature categories account for 35% each, the 500–1000°C is merely 11% and the above 1000°C is 19%, which cannot be directly supplied by nuclear technology due to limitations to metals (Peakman and Merk 2019), see Figure 3.

It is important to note that there is considerable uncertainty on the heat demand by temperature range and fuel type (electric and non-electric) within the 'wider industry' segment in Figure 3, and when this is taken into account the two lowest temperature categories account for 28% and 29%,

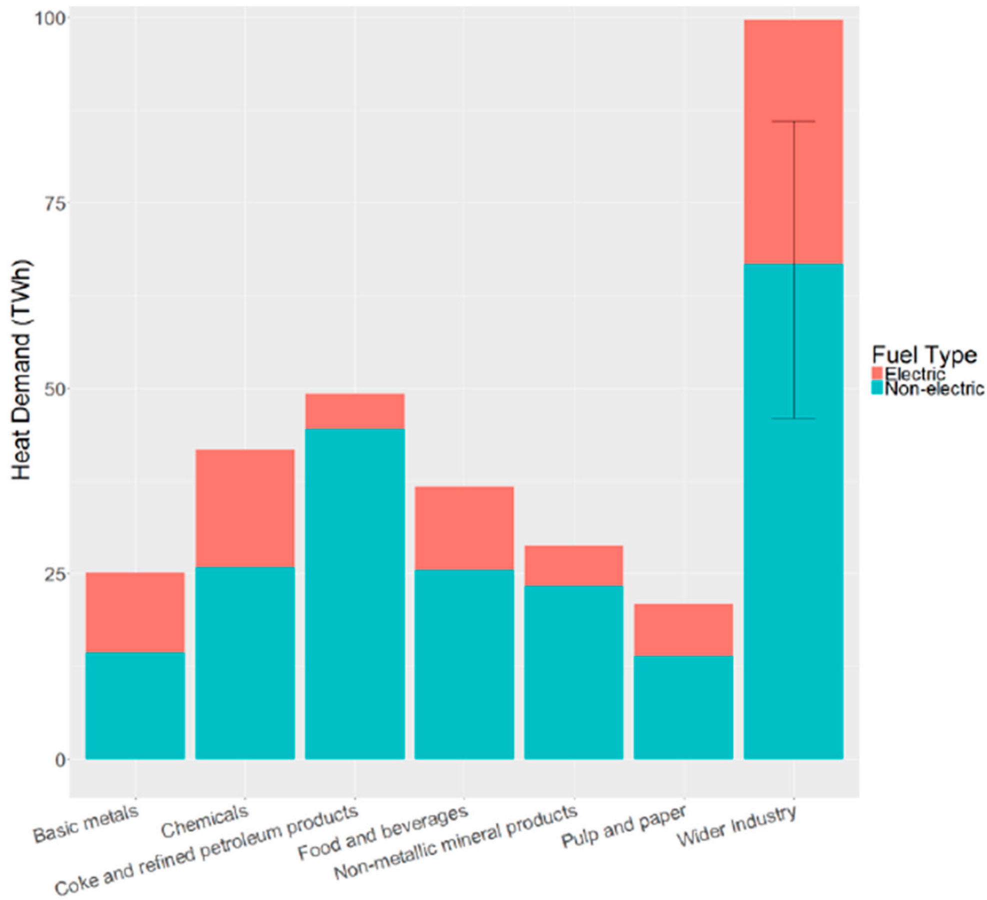

Figure 3. UK industrial heat demand per year by sector. Source: (DECC 2013).

respectively. The 500–1000°C is merely 15% and the above 1000°C is 28%, which cannot be directly supplied by nuclear technology due to limitations to metals (Peakman and Merk 2019).

A similar analysis has been carried out for the US (Bragg-Sitton et al. 2020) where the categories are different and therefore the mix, compared to the UK. However, the overall result is similar. Finally, in Figure 4 the global situation is presented. Clearly, it is only the manufacturing of glass and cement where direct nuclear heat will have any problems. That said, there are reactor concepts that operate at 1000°C, see Huke et al. (2015), but they are still in the early development stage. Thus, to design an effective energy system, we must take into account the industry structure of a given country.

Second, transport of heat is difficult and expensive. The need for a pipeline, thermal isolation, pumping, and the corresponding investments, heat losses, maintenance and pumping energy requirements make it impractical to transport heat beyond distances of a few kilometres or, at most, some tens of kilometres (Csik and Kupitz 1997). The implication is that the nuclear facility must be in relatively close proximity to the industrial sites. Recent studies show that at large scale (15–150 MWth), the heat from an LWR is more cost-effective than natural gas combustion up to a 1 km distance for the heat transported from the LWR to the industrial process (Knighton et al. 2020).

Third, the reliability requirements are key. For most Liquified Natural Gas (LNG) terminals, as in this study, electricity is not available from a nearby power station or reliable public grid

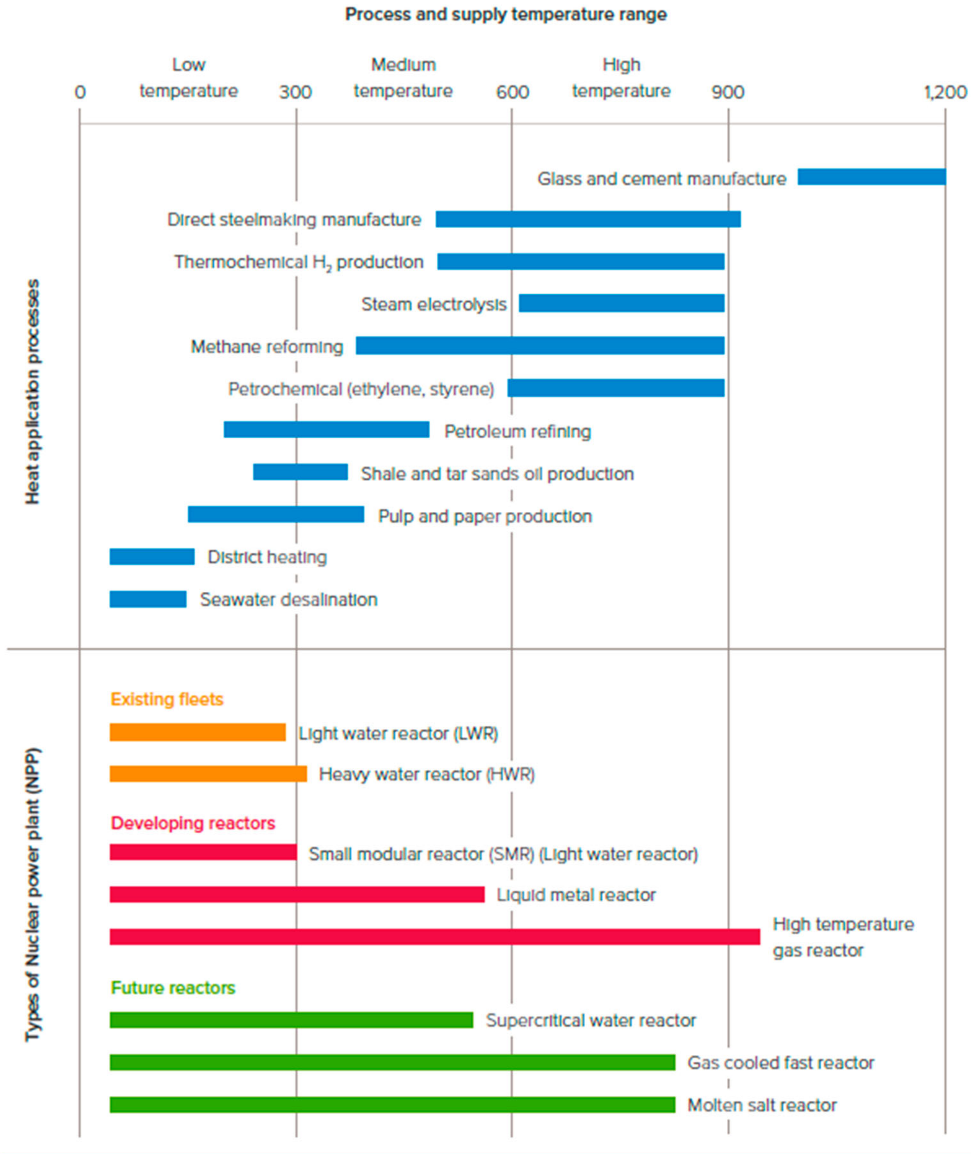

Figure 4. Temperature ranges of heat application processes and types of nuclear power plant. Source: (IEA 2017).

(Devold, Nestli, and Hurter 2006). Yet, a common feature of practically all industrial users is the need for assurance of energy supply with a very high degree of reliability and availability, approaching 100% in particular for large industrial installations and energy-intensive processes (Csik and Kupitz 1997). For example, a shutdown of an LNG plant creates both a safety hazard and a major loss of production taking up to 48 h to come back on line (Devold, Nestli, and Hurter 2006). Availability and reliability of a reactor, however, can never reach the nearly 100% levels required by most large heat users. Consequently, redundancy is needed (Csik and Kupitz 1997). One option is a few SMRs instead of one larger, nuclear power plant.

In general, processes that integrate well with LWRs are those that require substantial water evaporation (specialty chemicals, chlor-alkali, paper and pulp, and food processing) or have large electrical and thermal demands (Knighton et al. 2020). Yet, about 99% of the industrial users are included in the 1–300 MWth range, which accounts for about 80% of the total energy consumed but some need up to 1000 MWth (Csik and Kupitz 1997). Hence, purely thermal demands needed for a particular process are unlikely to consume all of the energy generated by an LWR; therefore, large electrical demands, likely electrolysis processes (either chlor-alkali, water splitting, or alkane deprotonation), will be required to effectively use the entirety of an LWR's output (Knighton et al. 2020) or alternatively deliver some power to the grid. Therefore, SMR presents a particularly interesting proposition for cogeneration (The Royal Society 2020), but the power output and consistency of LWRs are attractive for specific applications that could be seen as a transition stage for later when next-generation SMRs can be implemented (Knighton et al. 2020).

Therefore, the ultimate solution is to create an industrial energy park (Knighton et al. 2020) to minimise all types of losses. Hence, close proximity and the usage of SMRs are the two most energy-effective approaches to satisfy thermal heat requirements.

Since cogeneration depends on context, as discussed earlier, this paper focuses on the Hammerfest LNG (Melkøya) terminal in northern Norway owned by Equinor. There is much public debate about this LNG terminal because it is the largest point emitter of climate gases in Norway. Some want to electrify it using wind power whereas others want to use nuclear power and others want to keep it as it is (mostly gas-powered). In the recent application for concession to the Norwegian government by Equinor (NVE 2023), they have not considered nuclear power. Therefore, in the next section both wind- and nuclear power are analysed. With gas being the most commonly used balancing- and backup power for renewables in 26 countries of the Organisation for Economic Co-operation and Development (OECD) countries (Verdolini, Vona, and Popp 2018), and the current energy crisis in Europe in mind, this study can also be interesting from a strategic point of view.

4. The Melkøya LNG terminal case

The Melkøya LNG terminal receives gas from Snøhvit field in the Barents Sea, and currently 5 gas turbines with heat recovery satisfy the demand of 200 MWe effect and 140 MWth effect with

Figure 5. The approximate location of Hammerfest LNG Terminal Melkøya.

100% availability. In addition, the plant has a grid connection of 100 MW capacity typically utilised 50% (NVE 2020). The Norwegian Energy Regulatory Authority (NVE) has assessed the application from Equinor concerning building, owning and operating necessary electrical power infrastructure to secure the electrification of Hammerfest LNG (Melkøya), see Figure 5 for the location. The Snøhvit Future project, see Figure 6, of Equinor is stipulated to cost 13.2 bn NOK[3] consisting of[4]:

(1) 2 main elements – the Snøhvit Land Compression and Snøhvit Electrification.
(2) Compressor, power transformation station and electrical steam boilers on the Melkøya facility.
(3) The power grid will also be expanded with a power transformation station on Hyggevatn and a grid extension from Skaidi to Hammerfest.

The project is to cut CO_2 equivalent emissions by 850,000 tonnes per year commencing in 2028, but a complete electrification will change the energy demand requiring 300 MWe effect in addition to the grid connection of today. A future planned upgrade of Snøhvit will add another 70 MWe demand (NVE 2020). The future upgrade will also be applicable to any nuclear alternative.

The possibility that power can be interrupted during operation of an All Electric Drive system must be factored in because such a power interruption will typically lead to a shutdown of the entire plant. A full shutdown in an LNG plant creates both a safety hazard and a major loss of production. It takes up to 48 h to come back on line (Devold, Nestli, and Hurter 2006). Therefore, the 100% reliability target with a risk buffer is crucial in this analysis.

The analysis is addressed by first modelling the capacity required to meet demand with 100% reliability in Sections 4.1 and 4.2. Then, the investment alternatives are discussed in Sections 4.3 and 4.4, and all the information is combined to produce the LCOE estimates in Section 4.6. Note that these LCOE estimates, particularly for the Wind alternative, are not the System LCOE for wind power as such but for the specific Wind alternative at hand. This fact gives the Nuclear alternative an edge by the nature of nuclear power being thermal, dispatchable with a large electric output despite losses.

Figure 6. Illustration of the Melkøya LNG Terminal upon completion. Source: Equinor.[10]

Note that the System LCOE is basically the same as the LCOE but the system boundary is no longer the asset itself but the entire impacted system. The System LCOE concept was initially presented by Ueckerdt et al. (2013), and it represents an attempt to overcome the limitations of LCOE as explained in detail by Emblemsvåg (2024).

4.1. Capacity modelling wind power

To model the available capacity, the production data for price area N04 in Norway is used. From 20 years of data, the seasonal variability is calculated and also the hourly variance. These two are subsequently used to model a 'typical year'.

The challenge is that the current install base of 1159.3 MW is far too little. In Figure 7 we see the production curve for 2022. Clearly, with a 100% reliability target and up to 370 MW in demand, the LNG terminal will suffer multiple blackouts every year. Indeed, there are 13 h per year with less than 1 MWh produced! In fact, there is 80% probability that the production will be 370 MWh or less in any given hour of the year.

To amend this situation, the proposal by the government is to add another 670 MW.[5] Assuming the same geographical mix and production profile with respect to wind conditions as the existing 1159 installed MW capacity, the capacity model of a typical year is scaled accordingly. The result is the monthly production profile shown in Figure 8. By using all the data over the last 22 years, we can simulate 10,000 years of production by using Monte Carlo simulations. The resulting figure therefore also includes uncertainty. Note that the entire model is calculated 1 h resolution but for presentation purposes, the figures are presented at suitable aggregation levels depending on purpose.

4.2. Capacity modelling nuclear power

The capacity modelling of nuclear power plants is far easier. Apart from unplanned outages, just as for wind power, the capacity modelling becomes a matter of maintenance planning. Essentially, it is

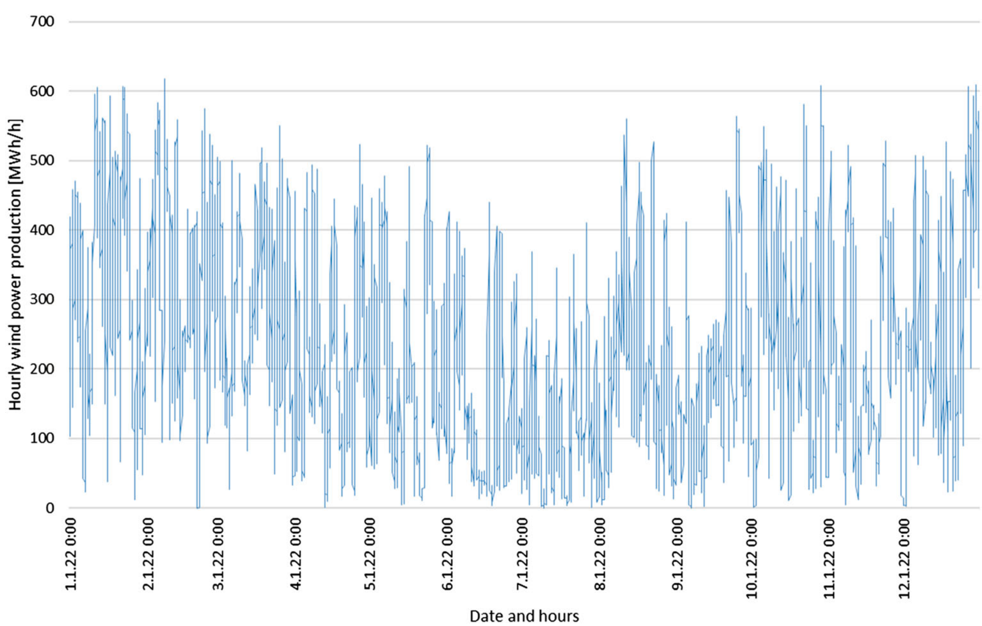

Figure 7. Hourly wind power production in N04 in 2022 [MWh/h]. The figure is made by the author using data from NVE.[11]

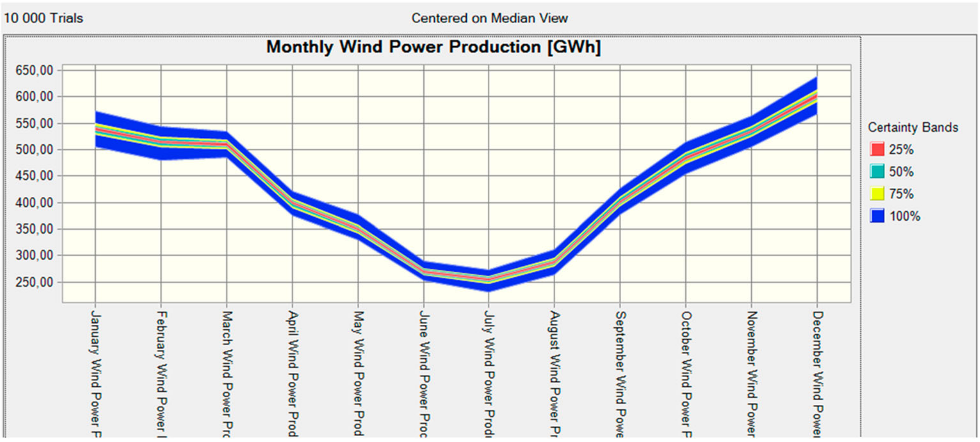

Figure 8. Monthly wind power production profile including uncertainty in the model.

important to avoid all reactors needing maintenance at the same time or on a high load time, such as in Winter. With the demand requirements from the Melkøya LNG terminal, it makes sense to also utilise the thermal rest energy for backup purposes. Deterministically speaking, the Nuclear alternative offers 300 MW firm electric power and 600 MW firm thermal rest power. Clearly, there is a very large thermal extra energy that can be utilised locally for district heating, maybe even a local swimming hall since the ocean outside is cold year-round and other good ideas are not included in this study.

Note that with a large thermal source of power and significant amount of thermal rest energy, even after providing the local community with various services, there is an option of employing a thermal battery. For example, Conlon, Venetos, and Hume (2022) offer an interesting alternative although they also use gas exhaust as a source of energy. This is not included in the model since the electrification alternative does not have such a battery either.

4.3. The investment based on electrification and wind power

In addition to the 13.2 billion NOK investment, the operating costs of the electrification itself will add another 158 MNOK (NVE 2023). We must also estimate the costs of the 670 MW of additional wind power proposed by the government and the cost of wind power of the existing wind power plants. In the model, all the wind power in N04 is allocated to Melkøya for simplicity, resulting in a total wind power capacity of 1829.3 MW. This wind power is exclusively land-based, and NVE[6] provides the data needed. Since this is a conceptual study with limited accuracy, the LCOE for wind power is directly with the inherent uncertainty that the parameters used by NVE may be slightly different than those in N04. The LCOE calculation by NVE uses a discounting factor of 6.0%, investment cost or capital expenditure (CAPEX) of 10 MNOK/MW and Operational Expenditures (OPEX) at 299.4 NOK/MWh in 2021 and 221.5 NOK/MWh in 2030.

In the model, the 2021 estimate is used because the equipment inflation of 38% witnessed over the two years, see Ferris (2023), is not included in the analysis of NVE. Indeed, the global benchmark LCOE has temporarily retreated to where it was in 2019, according to Fine (2022). However, the temporary nature of the reported 7% increase is questionable since costs have continued to rise even more to this date (September 2023). Therefore, to have a robust uncertainty modelling concerning the LCOE, the 2030 estimate of NVE is used as a lower end and a 15% increase of the 2021 estimate is used as the high end.

It is important to realise that these LCOE estimates use a system boundary of the wind power plant, i.e. asset level, which is common practice (Emblemsvåg 2024), and do therefore not incorporate the total costs. In addition, we must determine the balancing- and backup costs to secure 100% reliability. Due to the intermittent nature of wind power as discussed earlier, we need to perform a system simulation.

The most difficult aspect of this analysis is to estimate the likely cost of importing electricity from Sweden (SE1 price area), Finland (FI area) and further south in Norway (N03 area) particularly when a large variable consumer (as seen from the neighbouring price areas) is added with long transmission lines and losses. See Figure 5 where all major transmission lines are shown.

In Figure 9, we see the prices in the neighbouring price areas since 2019 on a monthly basis. We see clearly the escalating prices since summer 2021 with high volatility in the latter half of 2022. The average prices in the three price areas are 411.30, 344.31 and 794.39 NOK/MWh in SE1, N03 and FI, respectively. However, a major consumer like the Melkøya LNG terminal is likely to obtain the best prices at *all* times, and for power-intensive industry there is also separate spot price in Norway shown in Figure 9. The average for the period, using linear interpolation since the prices are provided on quarterly basis by Statistisk Sentralbyrå (SSB)[7], we end up with an average of 56.74 NOK/MWh and a standard deviation of 40.38 NOK/MWh which is used in the simulation model.

It should be noted that Equinor has stated that they will use the existing gas power plant to provide balance- and backup power. Given the wind capacity curves discussed above, this idea will essentially negate the very purpose of cutting emissions as the rapidly changing wind power will essentially lead to the gas turbines having to run large parts of the year. The costs of such an operation are also unknown to the author, and therefore excluded in this study.

With the true spot prices in the same price areas as shown in Figure 9, it is obvious that if the Melkøya LNG terminal obtains the intensive power industry rates, as assumed here, there is a cost being shifted onto the local community of considerable size. The Net Present Value (NPV) of this social opportunity cost is estimated separately in the model using a social discount rate of 4.0%, which is used in a number of contexts in Norway (Liu 2018).

Note that a social opportunity cost is an externality of the analysis of Melkøya LNG terminal that arises from the fact that economically motivated decisions often affect people that are not directly involved in the transactions (third parties), and when they become large enough to constitute some kind of problem economists refer to them as externalities (Helbling 2010). In this case, we have so-called technical externalities since the indirect effects have an impact on the consumption and production opportunities of others, but the price of the product does not take those externalities into

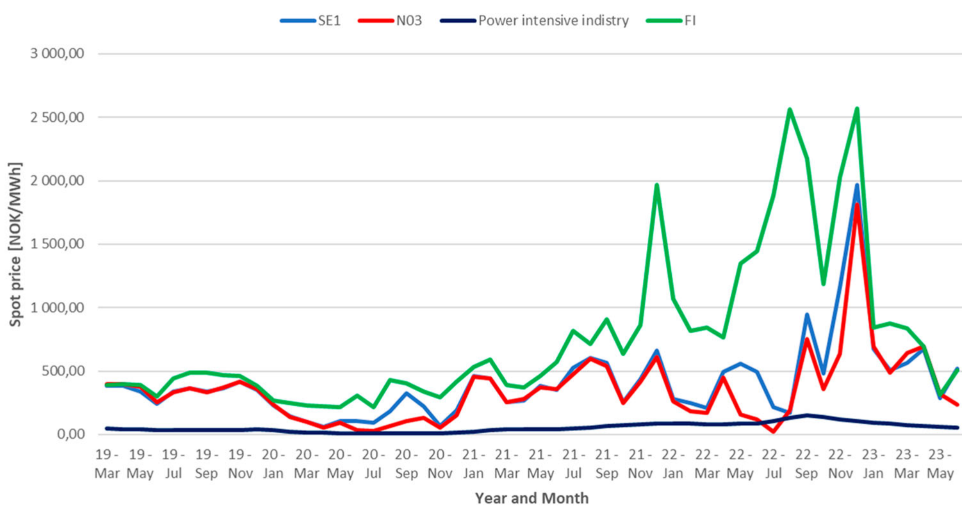

Figure 9. Monthly spot prices in SE1, N03, power intensive industry in Norway and FI.

account. Identifying and agreeing on policies for internalisation of social costs is difficult in general (Tirole 2008), and this case is no different.

4.4. The investment based on nuclear power

When it comes to nuclear power, the data offered by NVE are based on large, European LWR, which are completely different than those envisaged for Melkøya in this study. Therefore, the cost calculation must be built up in this study. Since the data for SMRs are unreliable because they are based on cost modelling and prototypes and not commercial power plants, it is important to focus on robustness over accuracy. The fact is that factory-produced commercial nuclear power reactors have never been deployed, so there is little understanding of how SMR cost will evolve (Lovering and McBride 2020). Therefore, in this study, the most industrialised LWR design built by a democratic country is used as baseline, and that is the OPR 1000 and its successor APR 1400 from South Korea.

The latest construction completed in the Barakah Nuclear Power plant in United Arab Emirates (UAE) with 5600 MW of installed capacity had a CAPEX of 24.4 bn USD, according to WNISR (2020). Translated into Norwegian currency (NOK) with NOK 10 per 1 USD as exchange rate, this is about 43.5 MNOK/MW, which is at the low end of the study performed by Abou-Jaoude et al. (2023). This case is also interesting because UAE, like Norway, has no prior commercial nuclear reactors of any sort. Furthermore, the APR 1400 is a relatively new design so there is a first-of-a-kind (FOAK) premium. According to Abou-Jaoude et al. (2023), the FOAK premium is about 1.4 implying that a design built later will cost at least 1.4 times less. Then, by dividing the capacity into two units, Melkøya would need 2 SMRs of 150 MW installed capacity costing 9.3 bn NOK including financing (whether these costs are included in the estimates for the wind power alternative is unclear).

Indeed, even with modest learning rates of 10–20%, SMRs could reach cost parity with large reactors after a dozen units built, even if they start out at twice, and later they can even reach cost parity with fossil fuel by 2050 (Lovering and McBride 2020). This paper has clearly not stretched nuclear that far, but the case becomes obvious if SMRs obtain such cost levels.

When it comes to OPEX, the study of Abou-Jaoude et al. (2023) is the best-identified source. Since the SMRs have a number of simplifications compared to large LWRs, the midpoint between low end and mid-end is used as an estimate, i.e. USD 20 USD/MWh or 200 NOK/MWh, which is consistent with O&M (Operations & Maintenance), fuel and waste costs of the APR 1400 in Figure 1. Note that this analysis presupposes that there is a nuclear waste facility somewhere so that Equinor does not have to build it but will pay to use it according to volume (*pro rata*).

The same discounting factor from NVE for wind power (6%) is used. Since a nuclear power plant has more than twice the life-span of a wind power plant, there will also be a residual value after the 25-year investment horizon that must be included. Using linear depreciation over 60 years, this amounts to 5.4 bn NOK nominally which after discounting becomes 1.6 bn NOK.

4.5. Summary of limitations and key assumptions

The discussions above result in a number of limitations and key assumptions that we must keep in mind when comparing the cost figures next:

(1) Industrial facilities require 100% reliability. Wind alone will never provide that, so balancing and back-up power are required. All the wind power plants in N04 region are providing power to the Melkøya LNG plant. Nuclear does not require such balancing, but to increase the reliability 2 reactor units are required to take maintenance into account.
(2) Both alternatives have impact on the wider system, which is why system costs are computed as well as System LCOE. Notably, the Wind alternative requires balancing- and backup power,

while the Nuclear alternative presupposes the existence of a waste management system somewhere in Norway. Nuclear, also has a lot of rest energy that can be used which is not incorporated into the model. On the flip side, the Nuclear alternative will incur some integration costs to the current facility, but most likely small in comparison to the Wind alternative since the current facility also has thermal power sources (gas). On the other hand, it may be that this retrofit displacing an existing thermal power supply also has incurred some extra costs associated with the Wind alternative (in the 13.2 bn NOK CAPEX) that would have been eliminated if the facility was designed for electric power from the onset. These costs are also ignored.

(3) The costs for the Wind alternative are based on 2021 numbers, which are most likely too low given the high inflation in equipment costs seen in the last 2 years. It is assumed that this very high equipment cost inflation will not continue, and therefore mostly ignored.

(4) To estimate the nuclear costs, the costs obtained from the most standardised reactor design currently available – the APR 1400 – are used and scaled down in size to fit the purpose here.

(5) Due to the long life-span of nuclear power plants (often 65 years), the economic rest value of the nuclear power plant after the analysis horizon of 25 years, is estimated as a discounted terminal value based on 60 years linear depreciation, which obviously is a rough approximation since this cannot be known until it is actually sold.

(6) Some non-financial and non-technical issues are ignored in this study but discussed in Section 6.

More details about the actual cost numbers are provided next.

4.6. Calculating- and comparing the LCOEs

The cash flow analyses needed to calculate the Total System LCOE for the two alternatives are shown in Table 1. The base case represents the cost numbers without any inflation or discounting effects. Due to the simplicity of the cost modelling of the financial issues, only OPEX is adjusted with inflation (assumed to be 5% per year flat) but all costs are discounted. This flat inflation is the general inflation in society and not the equipment-specific inflation mentioned earlier. Also, the terminal value of the reactor investment is included because after the 25 years the analysis horizon covers, there are another 40 years of good operation where nuclear power plants are typically highly competitive.[8]

If we compare the two alternatives, we see that the CAPEX of the Wind alternative is 3.9 bn NOK more expensive, while the OPEX for the Nuclear alternative is 341 MNOK higher every year. However, supplying all the wind power costs in discounted terms 24.3 bn NOK throughout the 25 years. In total, the Nuclear alternative therefore comes out far cheaper (about half the cost).

Table 1. Cost summary for the two alternatives.

WIND	Base case	1	2	3	…	24	25
Annual balancing- and backup power	14	14	14	14	…	14	14
Snøhvit Future CAPEX	13,200	13,200					
Melkøya additional OPEX	158	158	166	174	…	485	510
Cash flow	**13,877**	**13,215**	**16**	**17**	**…**	**38**	**39**
Discounted cash flow	13,527	13,215	15	15	…	10	10
LCOE wind power	24,260						
Total Discounted Asset Costs	**37,788**						
Social opportunity cost	72	72	72	72	…	72	72
Discounted social opportunity costs	1165	72	69	66	…	29	28
Total Discounted System Costs [MNOK]	**38,953**						
NUCLEAR	**Base case**	**1**	**2**	**3**	**…**	**24**	**25**
Nuclear CAPEX	9321	9321					
Nuclear residual value							−5438
Nuclear OPEX	499	499	524	551	…	1,534	1610
Cash flow	**27,715**	**9821**	**524**	**551**	**…**	**1534**	**−327**
Discounted cash flow	19,145	9821	495	490	…	402	−945
Total Discounted System Costs	**19,145**						

However, with all the variability of wind power, we cannot make a decision using deterministic figures. Therefore, a Monte Carlo simulation is run using ORACLE Crystal Ball with Latin Hypercube sampling for maximum accuracy and 10,000 trials to simulate 10,000 years to handle all possible operational conditions. How this works is explained in detail by Emblemsvåg (2003). The results for the Monte Carlo simulations are shown in Figure 10 and thereafter. Clearly, there is very little probability that the Wind alternative will even come close to the Nuclear alternative.

From Figure 11, we see the number of hours traded including the energy shortages that will arise and the amount of electricity involved. We see that on average, about 2750 h of grid support over 100 MW grid connection will be required demanding 224 GWh from the grid. Among these hours with grid support, there will also be about 1750 h with outright energy shortages on Melkøya LNG terminal requiring almost 200 GWh of additional purchase of electricity from neighbouring price areas. Hence, the Wind alternative fails to deliver sufficient electricity to Melkøya LNG terminal. Not only will the Melkøya LNG terminal suffer major electricity shortage risks, but it will most likely transfer these risks due to the 100% reliability requirement to society and in the process incur substantial social opportunity costs locally.

In essence, the Melkøy LNG terminal will crowd out local industries as seen in Figure 12 due to lack of electricity and superior financial strength and probably better procurement agreements on top. The most likely value is around 1 bn NOK in net present value, which can run as high as 5 bn NOK. There is also a chance (about 10% probability) that the social opportunity cost will be negative, i.e. produce a social opportunity benefit through overproduction of on average 1700 GWh per year, which amply demonstrates the challenges with renewable energy – it varies from overproduction to lack of production frequently.

Note that these social opportunity costs are included in the total System LCOE, which is shown in Figure 13. The System LCOE is essentially the Total Discounted System costs divided by the energy used. In the Nuclear alternative, only the used thermal energy is included in addition to the electric power. Hence, deterministically speaking, the Nuclear alternative will beat the Wind alternative with 275 NOK/MWh, as shown in Figure 13. The System LCOE numbers for the Wind alternative, however, do not include the cost hikes in wind turbines and other related equipment witnessed in 2022 and so far in 2023, which means that the System LCOE numbers for Wind can easily get worse by the time the Melkøya LNG terminal is electrified.

It is also likely that there is some cost escalation for the Nuclear alternative, but it will be less since the material requirements per TWh produced for nuclear power are far smaller in volume

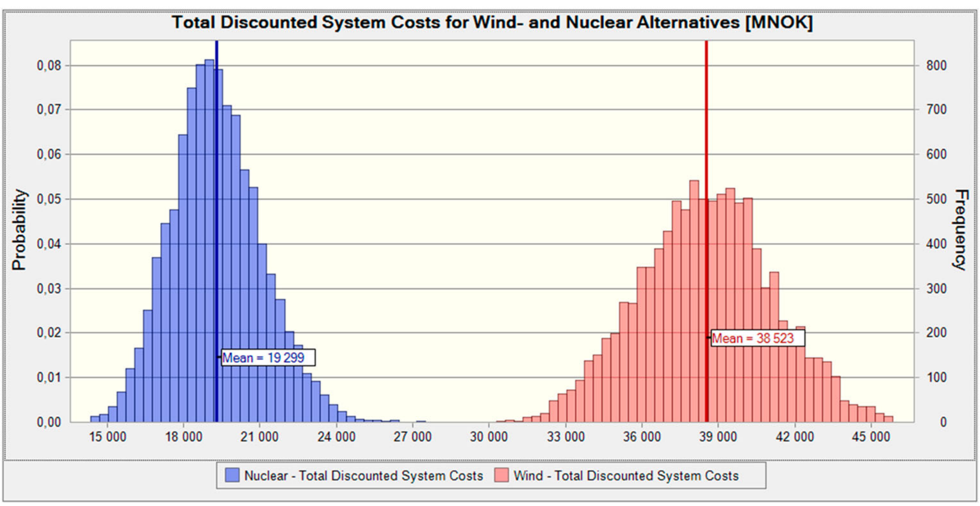

Figure 10. Comparing the Total Discounted System Costs for the Wind- and for Nuclear alternatives.

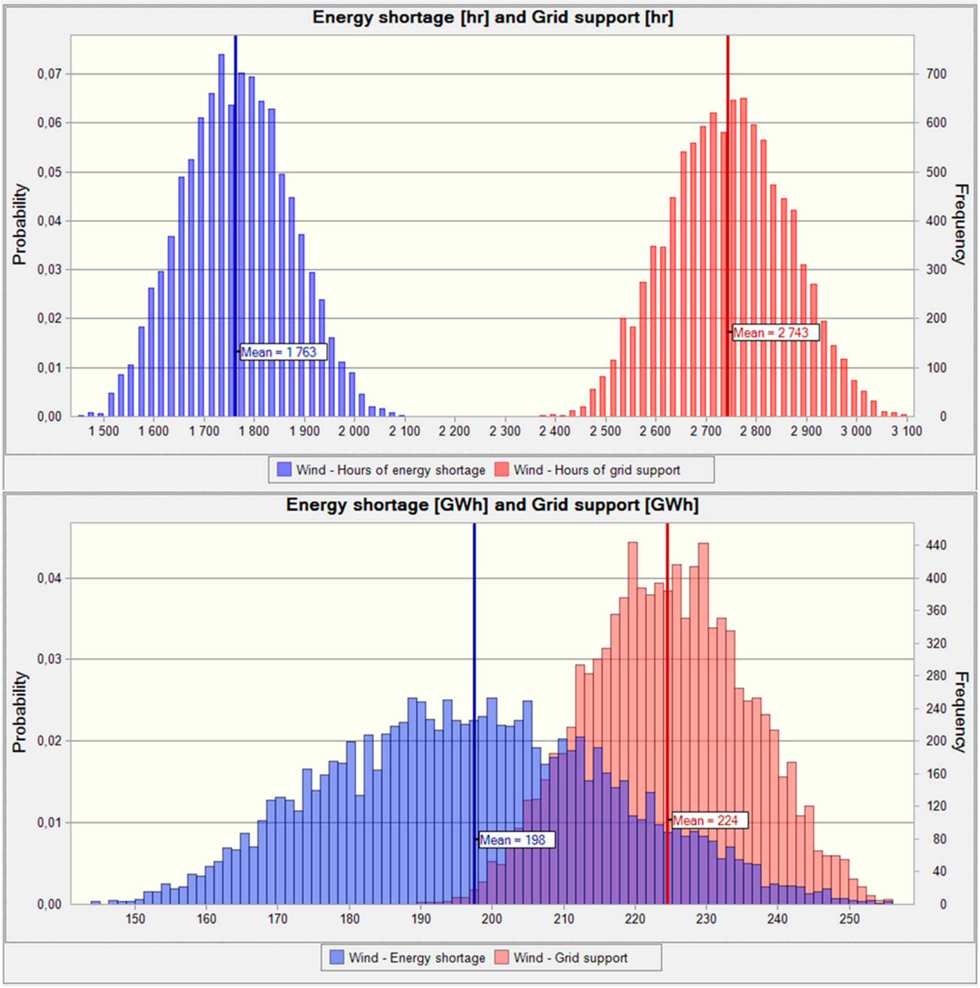

Figure 11. The usage of the 100 MW grid support and outright energy shortages.

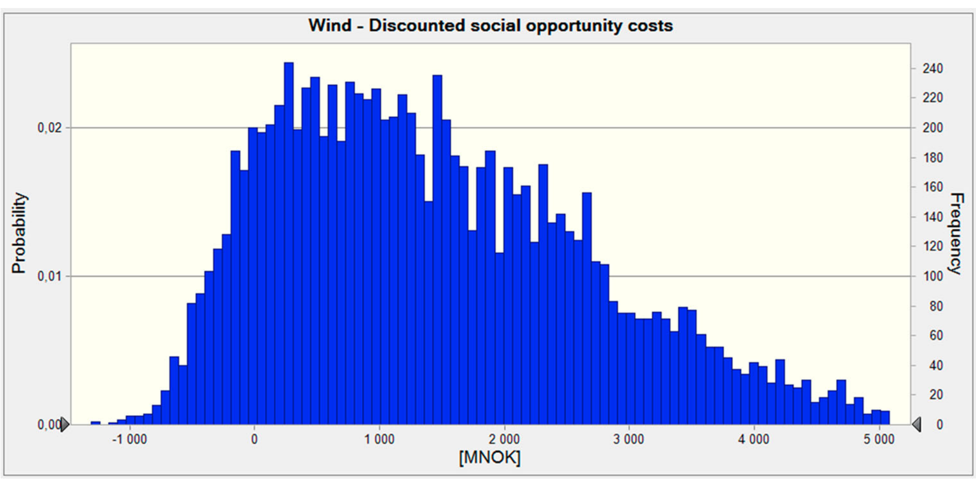

Figure 12. The discounted social opportunity cost.

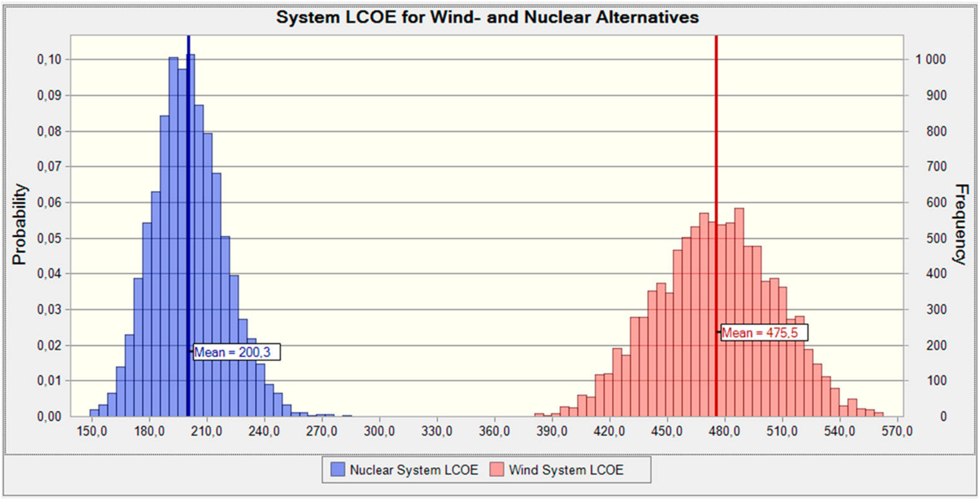

Figure 13. System LCOE [MNOK] for wind- and nuclear alterntives.

than for wind power or any other power source, and it consists mostly of abundant materials such as concrete and steel (US DOE 2015).

The Nuclear alternative also has a great advantage in that the thermal rest energy can be used directly by the LNG terminal. This lowers the System LCOE by allowing lower nameplate capacity and more energy output for the same nameplate capacity. The capability of using the thermal rest energy lowers the System LCOE for the Nuclear alternative by approximately 20%.

The sensitivity analysis in Figure 14 displays the sensitivities for the difference between the Wind alternative and the Nuclear alternative. The analysis includes all parameters in the model, out of 8789 parameters in total, that are both associated with uncertainty and have a higher rank correlation than 5%. The sensitivity chart therefore pinpoints those parameters that impact the uncertainty in the modelling the most.

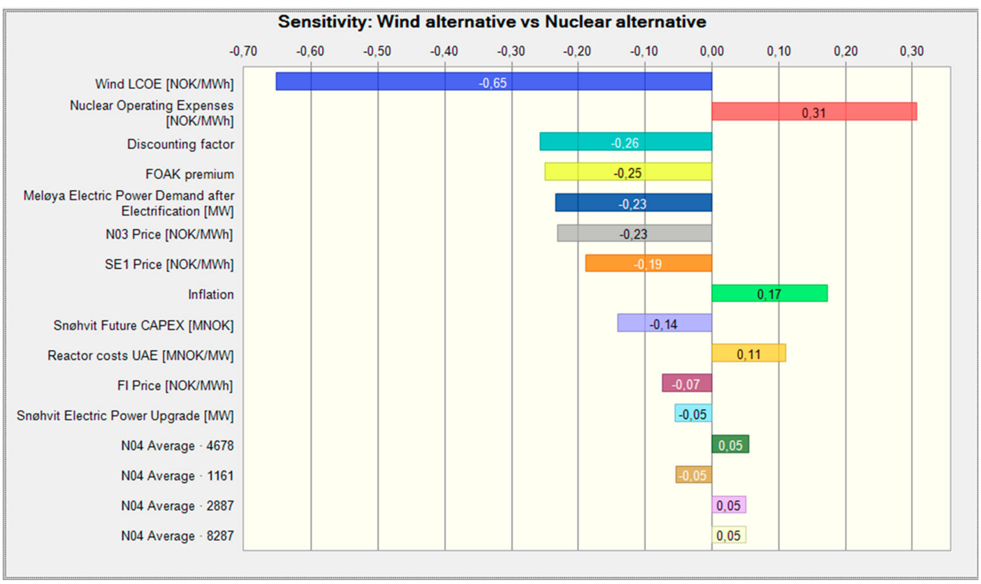

Figure 14. Uncertainty sensitivity analysis of the difference between the two alternatives.

The Wind LCOE (the LCOE of wind power plants in N04 measured on asset level) in the model is clearly an important uncertainty factor and particularly its development. If this increases it will have a strong, deteriorating effect on the Wind System LCOE. The second factor shows that the nuclear OPEX is critical for the Nuclear alternative. The FOAK has also a strong impact on the Nuclear alternative since this factor is the ratio between FOAK and NOAK (nth-of-a-kind), and in the model it is used to model what the Nuclear costs will approach in time to make it more comparable with the mature land-based wind power technology. The investment cost for the nuclear facility itself, comes quite far down on the list perhaps due to the fact that in lieu of information, the uncertainty is modelled as just ±10%.

The discounting factor impacts both alternatives, but since the Nuclear alternative has the longest tail on the cash flow – including the terminal value – the Nuclear alternative is impacted the most. The same holds for inflation, as well.

Then, we have a number of Wind alternative-related factors. Both the NO3 price, the SE1 price and FI price imply that the cost of providing balancing-/backup power for the wind power is important. This is consistent with the findings from Emblemsvåg (2020) who finds that an LCOE for wind including opportunity costs is at least 3 times higher than the LCOE used locally for wind power – the reason is the balancing- and backup costs. In this particular case, the system costs are actually lower than reported by Emblemsvåg (2020). The reason is that in this case, the balancing power takes place through very favourable long-term industry purchasing power agreements while Emblemsvåg (2020) bases his analysis on spot prices applicable to all customers in a grid.

We also have the investment costs (CAPEX) of the Melkøya LNG terminal itself and the Snøhvit upgrade. The uncertainty of those parameters is unknown but modelled as ±10% since no other information is available. However, there are significant execution risks in such large projects. The last four parameters in Figure 14 are related to the Wind alternative only, but the fact that they sometimes have positive impact and negative impact indicate that we have reached the limit of where random variations in a Monte Carlo simulation start to be significant, as discussed by Emblemsvåg (2003) including countermeasures. Such countermeasures are not useful here due to the level of accuracy for conceptual studies.

There is also a second way of using sensitivity analyses called tracing, as discussed and exemplified by Emblemsvåg (2003) in detail. By modelling all the uncertainty distributions of the parameters in the model by a symmetric- and bounded distribution, for example a triangular with ±10% spread, we can measure which variables have the greatest impact on the results themselves, i.e. the expected values. This approach is useful for improving investment alternatives. The sensitivity chart for that purpose is shown in Figure 15.

Again, the wind LCOE for the individual wind power plants the Melkøya LNG terminal rely on in the Wind alternative, comes up on top when we analyse the sensitivities of the difference between the two alternatives. In fact, almost all the factors are related to wind power except four.

The four parameters related to the Nuclear alternative are all related to either the investment or its operational expenses, with the same interpretation as in the uncertainty-related sensitivity analysis discussed earlier.

5. Critical review and future work

The analysis performed in this paper is limited by a number of factors, notably the lack of access to detailed operational data of Melkøya LNG terminal. However, since this is equal for both alternatives it has limited relevance as to the comparison of the two alternatives, but it will certainly have an impact on the absolute levels of energy consumed and therefore costs. Since this is a conceptual study where two alternatives are pegged against each other, this limitation is therefore of minor importance although we should be aware of it to avoid overinterpreting the results for this specific case.

A more interesting limitation is the available information concerning the cost levels at the time of decision-making as well as how the costs will be impacted by local siting issues such as terrain,

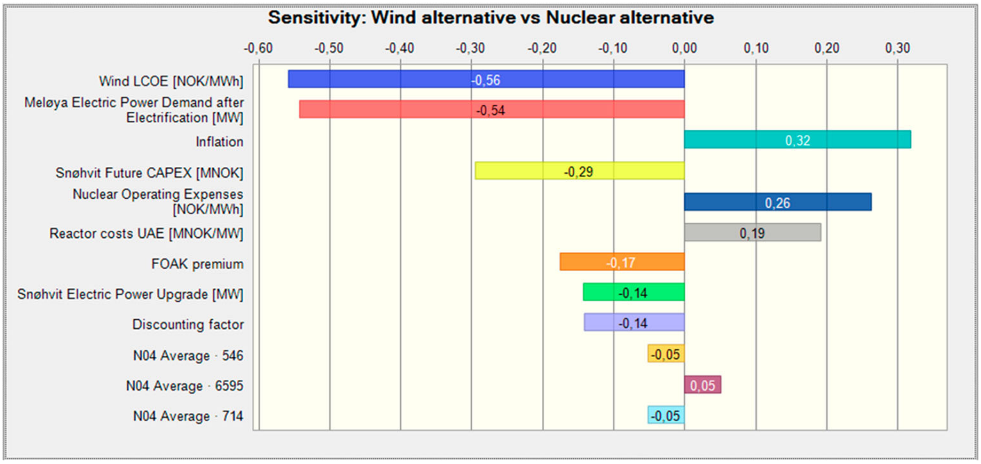

Figure 15. Tracing sensitivity analysis of the difference between the two alternatives.

how the local native people's rights will be implemented and so on. This can incur significant project execution costs that are today unknown, at least to the author of this paper. The two alternatives have a different risk profile in this respect.

The Nuclear alternative has a risk concerning the geological quality of the site itself on Melkøya or in the vicinity or wherever it is placed. With Norway having very old and stable rock formations, it is likely that this risk will have little impact. The greatest risk, however, is the politics in Norway which has excluded nuclear power over the last two decades, even in research. Thus, we have to argue this analysis from the point of view that a technology-neutral approach is permitted. Otherwise, the Nuclear alternative is, as of today, difficult or even impossible.

The Wind alternative has risks, as mentioned, related to area usage in a wide sense. This risk is substantiated by the Fosen case where licences for wind power development were ruled invalid by the Supreme Court of Norway due to the fact that the construction violates Sami reindeer herders' right to enjoy their own culture.[9] With Finmark and Troms being part of the heartland of the Sami people, such cases are likely to become many more involving both wind power plants and the power lines required to Melkøya.

It should be noted that the cost factors for both alternatives are a few years old and with the current inflation levels it can be many percentage points off. With the overall other uncertainties present, however, it is unlikely that this will not fundamentally alter the comparison of the two alternatives, and if it did – it is likely that this will strengthen the Nuclear alternative as noted earlier.

A very important factor for the Wind alternative, is the prices for the balancing- and backup power, as shown in Figures 14 and 15. Furthermore, from Figure 9 we see that these prices are increasing. From other countries with a high degree of wind power, we know that prices to industry increase as wind power penetration increase, as demonstrated amply by Germany as discussed by Emblemsvåg and Ôsterlund (2023). Thus, the Wind alternative is likely to grow worse with time.

Cases of this complexity obviously cannot be solved by a techo-economic analysis, such as this, alone. There are many other factors that come into play, as mentioned, that will impact the final decisions significantly. This is discussed next.

6. Using multi-criteria decision analysis to reach a final conclusion – future work

The concept and feasibility study presented is techno-economic and to some extent socio-economic. However, the socio-technological aspects are largely ignored because they in this case border into politics that would in itself be a research project worthy. Therefore, this section only briefly discusses the aspects and outlines how to address them in possible future work.

First of all, we must recognise that these aspects are multi-dimensional as well as qualitative and quantitative. That limits the available approaches for how to address them in a scientific manner. One of the best subjective methods for providing decision-support in multi-objective situations, is the Analytic Hierarchy Process (AHP) developed in the late 1960s and first publicised for a wider audience in numerous books such as Saaty (1990).

The AHP has been used in a wide array of situations such as resource allocation, scheduling, project evaluation, military strategy, forecasting, conflict resolution, political strategy, safety, financial risk and strategic planning (Saaty and Forsman 1992). AHP has also been applied in selecting suppliers (Bhutta and Huq 2002), business performance measurement (Cheng and Li 2001), quantitative construction risk management (Dey 2001) and selection of maintenance strategy and organisation (Emblemsvåg and Tonning 2003).

There are many key criteria that must be addressed in future work to reach a viable decision, in addition to the data accuracy discussed earlier, and all must be formulated in the matrix system of the AHP approach. The local native people's rights, the area usage of wind power and transmission lines also outside native people's areas, employment opportunities and broader societal impact are already noted. It has also alluded to the fact that the Wind alternative will crowd out local businesses and create a conflict concerning social opportunity costs. Most of these issues strengthen the Nuclear alternative.

Then we have legal issues on both alternatives including policies, regulations and potential resistance from various advocacy groups and non-governmental organisations (NGO). The Nuclear alternative, however, has a particular issue related to nuclear waste driven by public risk perception as demonstrated by Slovic, Fischhoff, and Lichtenstein (1979) as early in the late 70s. Here, there are endless debates on both sides also internationally between laymen as well as researchers. Norway has, on top, a historical precedent of opposing commercial nuclear power, which will undoubtedly impact the Melkøya LNG terminal case. Interestingly, both advocacy groups and NGOs are on both sides of the debate highlighting the different views of such projects. Obviously, both NGOs and advocacy groups will have a good opportunity to create legal roadblocks in the Melkøya case.

Anyway, once the criteria and issues are known, the next step in the AHP approach will be to rate them against each other through pairwise comparison. The AHP approach has a consistency check allowing only 10% inconsistency (Peniwati 2000) thereby preventing politics by ensuring logical consistency. This step will be challenging due to the politicised atmosphere of such cases. The final step where each alternative is to be assigned grades to each of these criteria will be even more challenging.

Thus, in the end, the Melkøya LNG terminal will therefore most likely be a political decision despite that the analysis presented here shows that the techno-economic- and the socio-economic case for the Nuclear alternative is strong. These political processes are very unlikely to follow anything that resembles the AHP approach outlined above, but that does not mean using AHP is useless. Researchers should strive to present their work with integrity to aid political deliberations and using AHP is a good tool for that in future work because it takes the politics out of science, but it cannot take the politics out of the decision.

7. Conclusions

Industrial facilities around the world that have so far relied on fossil energy, increasingly face difficult choices in their quest to cut emissions. In this paper, one such facility and its choices have been discussed. The Nuclear alternative is techno-economically better, but due to the importance of context for such facilities, we cannot directly transfer this finding to all such industrial facilities.

What appears to be a generic finding is that if the nuclear thermal rest energy can be utilised effectively, as in the Melkøya case, the nuclear power has a strong case over wind power because wind power requires more electric power and it also requires balancing- and backup power. This finding requires more research to verify, but as Smil (2020) notes in the context of Germany after 20 years of Energiewende;

> In 2000, Germany had an installed capacity of 121 gigawatts and it generated 577 terawatt-hours, which is 54 percent as much as it theoretically could have done (that is, 54 percent was its capacity factor). In 2019, the country produced just 5 percent more (607 TWh), but its installed capacity was 80 percent higher (218.1 GW) because it now had two generating systems.

The simple fact seems to be that regardless of how inexpensive a power system is, as long as it is not 100% reliable it is always necessary with two power systems and that comes at a high cost. For industrial facilities that require 100% reliability, the cost of the total power system will therefore be the relevant benchmark, and it will be higher than if the energy demands can be satisfied with one system. What is clear is that a technology-neutral approach should be used so that all alternatives can be investigated properly in all dimensions before any decisions are made.

Notes

1. Note that we often use 'th' or 'e' after MW and MWh (or the like) to denote that the number is thermal or electric. In this case, MWth implies that the thermal effect is 1200 MW. For thermal energy sources such as nucelar power, the thermal effect is therefore the total effect and normally 3 times higher than the electric effect unless there is cogeneration with a mix.
2. The coefficient of performance is specifically defined as $c = H_b/\Delta E$, in which H_b is the produced heat and ΔE is the difference between electricity in the pure electricity production mode and in the co-generation mode of operation (Barnert, Krett, and Kupitz 1991).
3. NOK (Norske kroner) is the currency of Norway and has the last year traded at around 10 per US dollar.
4. This information was accessed 2023-08-27 from https://www.equinor.com/news/20230808-governmental-green-light-snohvit-future.
5. Information obtained on 2023-08-24 from https://e24.no/energi-og-klima/i/Q7B2gR/mer-kraft-og-nett-i-nord-melkoeya-er-en-motor.
6. NVE has a website, accessed 2023-08-20, that offers the data, see https://www.nve.no/energi/analyser-og-statistikk/kostnader-for-kraftproduksjon/.
7. Data obtained on 2023-08-20 from https://www.ssb.no/statbank/table/09364/.
8. For example, in the US, depreciated power plants have a cost of about 30 USD/MWh, see https://www.statista.com/statistics/184754/cost-of-nuclear-electricity-production-in-the-us-since-2000/.
9. The ruling was accessed 2023-08-31 from https://www.domstol.no/en/supremecourt/rulings/2021/supreme-court-civil-cases/hr-2021-1975-s/.
10. Obtained 2023-08-27 from https://www.equinor.com/news/20230808-governmental-green-light-snohvit-future.
11. The website is https://www.nve.no/energi/energisystem/vindkraft/data-for-utbygde-vindkraftverk-i-norge/.

Acknowledgement

The author would like to thank the journal for its fast handling and very useful comments from the reviewers that improved the readability of the manuscript significantly.

Disclosure statement

No potential conflict of interest was reported by the author(s).

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Fremtiden til grønne, maritime drivstoff i Norge – en energianalyse

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Tidligere forskning viser at det finnes ikke nok energi tilgjengelig for å produsere grønne drivstoff for den internasjonale handelsflåten uten å skape store problemer for resten av verdens elektrisitetsforsyning. Skalaen er kort og godt for stor. Situasjonen for den nasjonale flåten i Norge er ukjent. Denne artikkelen vil analysere kraftbehovene som skal til for å produsere grønne drivstoff til den nasjonale flåten i Norge. Analysen viser at dieseloljen som selges til maritim bruk i Norge vil kreve 23 prosent av all elektrisk energi fra norske vannkraftverk. Dersom Norge må holde sin andel av den internasjonale handelsflåten med drivstoff, vil det kreve ytterligere 250 TWh i året. Den internasjonale handelsflåten er derfor langt utenfor rekkevidde for energisystemene på land, men det er mulig å skaffe nok grønt drivstoff til den nasjonale flåten i Norge, selv om det er meget krevende. Artikkelen diskuterer kort situasjonen med batterier og biodrivstoff også. De kan selvsagt bidra, men i liten grad løse utfordringene.

Introduksjon

Shipping står for omtrent 3 prosent av de totale klimagassutslippene i verden; for sammenligning litt høyere enn Tyskland sine totale klimagassutslipp (Olmer m.fl. 2017). Uten effektive mottiltak er disse utslippene forventet å vokse til 10–13 prosent av de totale klimagassutslippene (King 2022). Klimamålene krever dog det motsatte, og søken etter andre drivstoff enn fossile er derfor i full gang. (UNCTAD 2023) skriver at "The alternative energy fuels most suited for international shipping are primarily advanced biofuels and e-fuels (i.e., synthetic fuels), namely methanol and ammonia". For den nasjonale flåten har man flere valgmuligheter hva drivstoff angår, fordi reiseavstandene er mye kortere enn for den internasjonale handelsflåten, og Gamlem og Valland (2024) har publisert et godt oversiktsstudium for den norske offshoreflåten, som også er relevant for nasjonal shipping når det gjelder drivstofftyper generelt.

Alle disse nye drivstoffteknologiene, bortsett fra biodrivstoff, bruker hydrogen, og (Kim m.fl. 2020) illustrerer utfordringene rent teknisk – de er langt fra enkle. Hovedproblemet blir dog at det ikke finnes nok energi til å produsere hydrogen ved hjelp av elektrolyse av vann, fordi internasjonal shipping vil kreve nesten all elektrisk energi (over 10 300 TWh/år) i hele OECD om man skal basere seg på grønn ammoniakk[1] eller andre hydrogen-baserte brensler, som vist senere i denne artikkelen. Det vil åpenbart ikke fungere.

1 For mer informasjon, se https://snl.no/ammoniakk_-_energibærer.

https://doi.org/10.18261/naturen.149.1.4

Spørsmålet er om det vil fungere noe bedre for den norske nasjonale flåten som fyller drivstoff i Norge? Det spørsmålet blir adressert i denne artikkelen.

I neste seksjon diskuteres metodikken, mens resultatene er presentert i den etterfølgende seksjonen. Deretter følger diskusjon av resultatene, og til slutt konklusjonen.

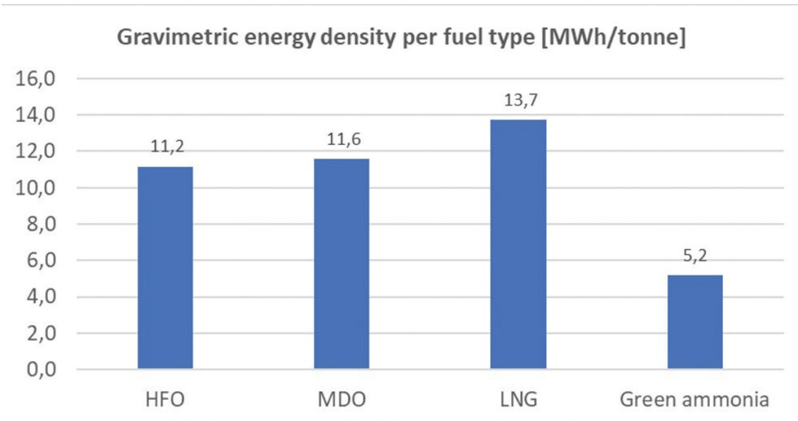
Metode

Vi legger til grunn at skipene skal operere som i dag, slik at motorkraften levert med et grønt drivstoff, slik som grønn ammoniakk, skal være lik motorkraften fra dagens fossile drivstoff. Den gravimetriske energitettheten for ammoniakk vil da gjøre det mulig å regne oss baklengs til antall tonn grønn ammoniakk som trengs. Til slutt beregnes energibehovet for å produsere de tonnene med grønn ammoniakk under den antagelsen at vi har neglisjerbare tap i kraftsystemet.

Vær obs på at *gravimetrisk energitetthet* ikke er det samme som *volumetrisk energitetthet* (Thompson og Taylor 2008). Gravimetrisk energitetthet er den mengde energi som er tilgjengelig per enhet masse, med enheter som [Joule/kg] eller [MWh/kg], og derfor ofte referert til som *spesifikk energitetthet*, mens volumetrisk energitetthet er den en fysiker vil omtale som *energitetthet*, og er målt som mengden energi per volumenhet med enhetene [Joule/m3] eller [MWh/m3]. Volumetrisk og gravimetrisk energitetthet er derfor relatert til hverandre via substansens tetthet [kg/m3], se for eksempel (Tozzini og Pellegrini 2013). Til slutt bør det nevnes at effekttetthet er den gravimetriske energitettheten i et gitt sekund.

De gravimetriske dataene brukt i analysen, er vist i figur 1. Data fra Foretich m.fl. (2021) avviker med kun 1,8 prosent fra Kim m.fl. (2020) når det gjelder tungolje, mens de andre fossile drivstoffkategoriene (slik som marin dieselolje, LNG, o.l.) mangler.

Selve analysen blir da en omregning via de gravimetriske tallene fra fossile drivstoff til grønn ammoniakk. Selv om denne analysen krever få tall, er tallene vedhengt en del usikkerhet. For eksempel, den totale EU-27 elektrisitetsproduksjonen i 2022 var 2 641 TWh, ifølge European Council (2023), mens *OurWorldInData* anslår den samme størrelsen til 2 812 TWh, noe som er 6,5 prosent høyere. «Triangulering» av data blir derfor utført der det er mulig, men det viktigste er at vi innser at analysen har en nøyaktighet på omtrent ±10 prosent. Fordi konklusjonene er så klare, er denne nøyaktigheten god nok.



Figur 1. *Gravimetrisk energitetthet [MWh/tonn] av drivstoff. Dette er forfatterens beregninger basert på data fra Foretich m.fl. (2021) og Kim m.fl. (2020). HFO står for* Heavy Fuel Oil*, eller* tungolje *på norsk. MDO er forkortelsen for* Marine Diesel Oil *(*marin dieselolje *på norsk), mens LNG er forkortelsen for* Liquefied Natural Gas *(*flytende naturgass *på norsk).*

https://doi.org/10.18261/naturen.149.1.4

Analyse og resultater

Analysen tar først for seg den globale situasjonen, dette for å sette en kontekst som sier noe om skalaen på den totale utfordringen, før vi ser på Norge. Fordi Norge har en vesentlig internasjonal handelsflåte, er analysen av den norske flåten begrenset til de skipene som faktisk fyller drivstoff i Norge. Det er i praksis det vi kan kalle nasjonal shipping. Det beregnes også hva Norges bidrag til den internasjonale handelsflåten bør være, om vi skal svare for våre egne skip.

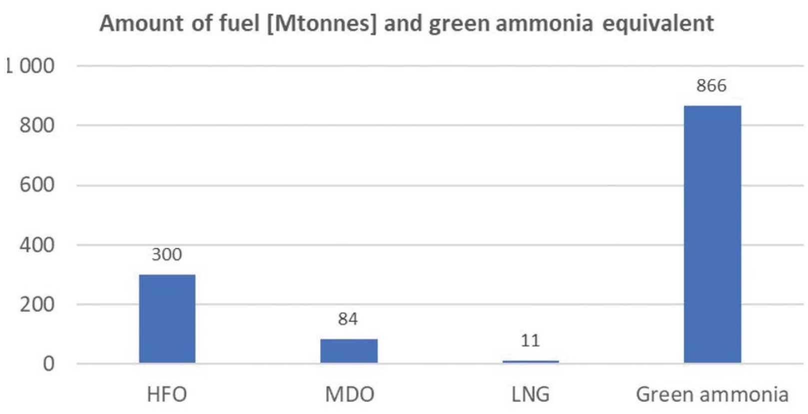
Den globale situasjonen

Det datasettet med best konsistens i forhold til andre datasett, er presentert av Concawe (2017). Dessverre er dataene deres fra 2012, og UNCTAD (2023) anslår at den årlige veksten i frakt fra 2011 til 2022 er på 4,9 prosent. Problemet er at veksten i frakt ikke nødvendigvis henger strengt sammen med økning i drivstoff-forbruk. Hvis vi legger til grunn vekstestimatene fra UNCTAD (2023) og fokuserer kun på HFO (eller *tungolje* på norsk), så blir estimatet av tungoljeforbruk i 2022, 50 millioner tonn for høyt i forhold til andre kilder. Derfor, for å holde oss på den konservative siden, brukes 300 millioner tonn tungolje, fra Jacoby (2022), for å skalere data fra Concawe (2017) til 2022. Det gir en økning for alle drivstoffkategorier på 32 prosent, som vist i figur 2.

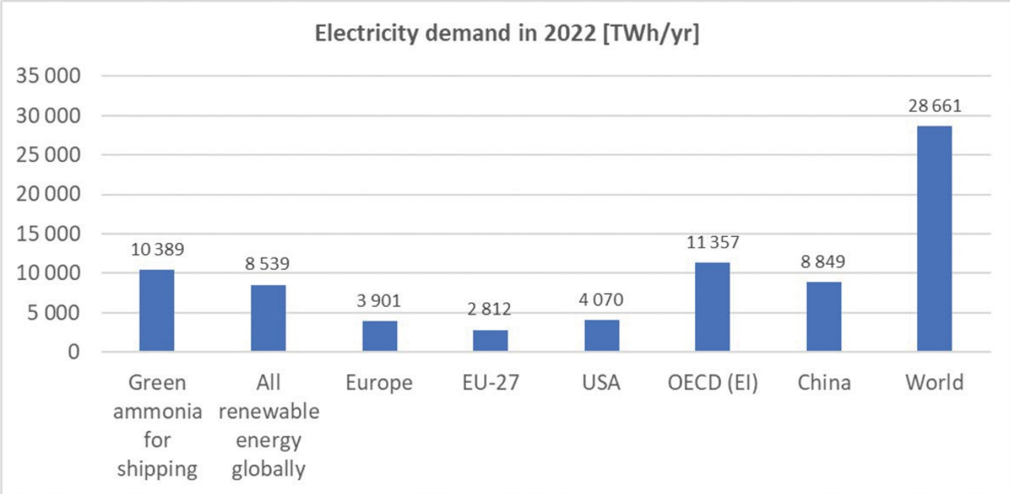
Til høyre i figur 2 ser vi den mengden grønn ammoniakk som må produseres for å gi samme energimengde til skipene som 395 millioner tonn fossile drivstoff gir. Det er basert på de gravimetriske energitetthetstallene i figur 1.

Produksjon av grønn ammoniakk krever 9–15 MWh/tonn (Giddey m.fl. 2017). Legger vi til grunn 12 MWh/tonn, vil det totale elektrisitetsbehovet bli 10 389 TWh i 2022. Usikkerheten er på ±25 prosent, noe som skyldes usikkerheten i energibehovet til elektrolyseanlegget som skal produsere hydrogengass. Uansett er mengden elektrisitet svært høy, som vi ser fra figur 3 – nesten like mye elektrisitet som er produsert i de 38 OECD-landene.

Legger vi til det faktum at alle store industrianlegg trenger kraft hele tiden (Csik og Kupitz 1997), vil variabel fornybar energi (sol- og vindkraft), som grønn ammoniakk fremstilles ved hjelp av, bli svært vanskelig å produsere i store nok kvanta, realistisk sett. For eksempel, hvis et LNG-anlegg må stenges ned, oppstår både en fare, i tillegg til at oppstart av produksjonen vil ta hele 48 timer (Devold m.fl. 2006). Denne kompliserende situasjonen er ignorert i analysen, men den ville i realiteten ha betydd at man måtte ha hatt ekstra mye ledig elektrisitetskapasitet tilgjengelig, med høy pålitelighet.



Figur 2. *Mengden drivstoff [millioner tonn] og den ekvivalente mengden grønn ammoniakk som gir samme energiproduksjon. MDO er forkortelsen for* Marine Diesel Oil *(*marin dieselolje *på norsk), mens LNG er forkortelsen for* Liquefied Natural Gas *(*flytende naturgass *på norsk). Forfatterens beregninger basert på data fra Concawe (2017) og Jacoby (2022).*



Figur 3. *Elektrisitetsbehovet for å dekarbonisere shipping [TWh/år], sammenlignet med store geografiske enheter.* All renewable energy globally *inkluderer også vannkraft.*

Det globale regnestykket går altså ikke opp rent energimessig, og det vil sannsynlig aldri gjøre det heller, om man trekker inn blant annet lufttrafikken og dens energibehov, som årlig bruker 220 millioner tonn flybensin (Tan m.fl. 2020). Grunnen er at man trenger 2,3 ganger mer energi – på grunn av stort «energitap» – når man produserer grønn ammoniakk ved hjelp av elektrisk kraft.

Hvis Norge måtte sikre grønn ammoniakk til sin andel av den globale handelsflåten, målt i lasteevne (dødvekttonn), så hadde den andelen vært på 2,5 prosent (UNCTAD 2023). Da ville Norge måtte frembringe ca. 250 TWh/år i kraft, for å produsere grønn ammoniakk til den norske delen av den globale handelsflåten. Det er åpenbart en håpløs situasjon å løse innen 2050. I neste seksjon vil vi derfor begrense oss til den delen av den norske flåten som opererer og fyller drivstoff i Norge.

Analyse og resultater av norsk, nasjonal shipping

Dataene for Norge er noe mer uklare enn de globale. Det opereres med en rekke begreper bare på skipsfarten – innenriks, nasjonal, nærskipsfart og flere. Dataene spriker også. Derfor er det mest fornuftig å se på salget av maritime drivstoff i Norge og bruke det som en tilnærming til «nasjonal» shipping, uten å gå nærmere inn på hvilke typer skip som faktisk har fylt drivstoff i Norge. Fordelen med en slik tilnærming, er at det solgte drivstoffet da faktisk er det som må erstattes med kraft fra Norge, om man skal selge like mye energi i fremtiden i form av grønn ammoniakk som man gjør nå i fossil form.

Statistisk Sentralbyrå fører statistikk over hvilke industrier som forbruker hvilke drivstoff i Norge, og i tabell 1 finner vi de kategoriene som er interessante å diskutere i denne artikkelen. Interessant nok er marine gassoljer[2] solgt i store kvanta også *utenfor* nasjonal shipping, og det er i all hovedsak til bergverk- og utvinningsindustrien, med 414 millioner liter. Anleggsdiesel er solgt mer til alle typer industrier, og derfor er det vanskelig å tilskrive engroshandelen av anleggsdiesel til en spesifikk industri.

Dessverre skiller ikke statistikken på marine gassoljer og marine dieseloljer, og vi bruker

2 For mer informasjon, se https://snl.no/gassolje.

https://doi.org/10.18261/naturen.149.1.4

derfor den gravimetriske energitettheten for marine dieseloljer, fra figur 1, korrigert for tettheten, for å beregne den volumetriske energitettheten. Det samme gjelder diesel.

Med den usikkerheten analysen har, legger vi derfor marin gassolje sammen med anleggsdiesel og får et totalestimat på 1350 millioner liter marin dieselolje per år. Med en tetthet på 850 kg/m^3 (Chervron 2007), er vekten 1,148 millioner tonn. Gitt samme spesifikke energiforbruket som vi brukte i forrige seksjon (12 MWh/tonn), blir det totale elektriske energibehovet per år 30,9 TWh, for å produsere den grønne ammoniakken. Det utgjør omtrent en femtedel av all norsk kraftproduksjon i et normalår.

Tabell 1. *Årlig salg av petroleumsprodukt etter næring, inkludert biodrivstoff der den er innblandet. Kilde: SSB*[3].

Alle tall er oppgitt i 1000 liter	**Anleggsdiesel**	**Marine gassoljer**	**Jetparafin**
Jordbruk, skogbruk og fiske	33 131	253 886	
Engroshandel	490 556	540 808	120 678
Sjøfart	29 066	526 485	
Lufttransport			716 430
Alle næringer	934 495	**1 963 332**	**1 081 957**

Eksisterende ammoniakkproduksjon i Norge fra fossile kilder vil komme i tillegg. Yara har allerede utført et studium og lansert prosjektet HEGRA (Herøya Green Ammoniakk)[4], og Yara alene ville ha krevd 4 TWh i året for å kutte 800 000 tonn CO_2. Dette kommer selvsagt i tillegg til det maritime behovet, som blir diskutert i denne artikkelen.

Et annet område er jetparafin. Jetparafin er i all hovedsak solgt til luftfartsindustrien, men med 180 millioner liter til bergverk- og utvinningsindustrien. Det betyr at å dekarbonisere luftfarten blir nesten like vanskelig som å dekarbonisere nasjonal shipping. De to industriene sammen vil kreve anslagsvis 50 TWh i året til produksjon av grønne drivstoff. Dette er langt utenfor rekkevidden for *dagens* kraftproduksjon i Norge, men i motsetning til det globale bildet, er faktisk dette *mulig* å få til.

Luftfart, sjøfart, anleggsmaskiner m.m. slapp ut 7,7 millioner tonn CO_2-ekvivalenter i 2023 (omtrent det samme som veitrafikken), mot de totale norske utslippene på 46,6 millioner tonn[5]. Det betyr at denne artikkelen adresserer kun 16,5 prosent av de totale klimagassutslippene fra Norge (utslipp fra handelsflåten er da ikke inkludert). Når produksjon av grønne drivstoff til -luft- og skipsfarten vil kreve rundt 50 TWh/år, og disse bare står for 16,5 prosent av klimagassutslippene i Norge, viser dette hvor vanskelig dekarbonisering frem mot 2050 vil bli.

Diskusjon

Selve analysen er meget robust, bortsett fra usikkerheten rundt energimengden som produksjonen av grønn ammoniakk vil kreve. Analysen legger til grunn midtpunktet (12 MWh/tonn). Det kan bli inntil 25 prosent lavere eller høyere, men ingen av deler vil endre konklusjonen substansielt. Uansett hvordan vi snur og vender på det, finnes det ingen kommersielle løsninger i dag for den globale handelsflåten (bortsett fra å fortsette med fossile drivstoff).

For Norge er situasjonen mye enklere om vi begrenser oss til den nasjonale delen av shippingen, men selv den er meget krevende og vil ikke fungere med dagens kraftsystem i Norge. Så har vi to teknologiske løsninger som ofte

3 Se https://www.ssb.no/energi-og-industri/olje-og-gass/statistikk/sal-av-petroleumsprodukt.
4 Se https://investinvt.no/news/yara-porsgrunn-has-been-offered-network-capacity-for-the-green-ammonia-project.
5 Kilde: https://www.ssb.no/natur-og-miljo/forurensning-og-klima/statistikk/utslipp-til-luft.

trekkes frem, som bør diskuteres i relasjon til de funnene som er presentert hittil: batterier og biodrivstoff.

Batterier

Store skip krever 250–300 tonn HFO (tungolje) hver dag, eller omtrent 3000 MWh pr. dag (Emblemsvåg 2024). Verdens største batteri, *Moss Landing Energy Storage Facility*, i California, har en kapasitet på 3000 MWh (Lewis 2023). Dette batteriet, på størrelse med et stort varehus, vil derfor kunne holde et stort skip med energi i ett døgn. Transitt-tiden fra Yokohama til Los Angeles er i beste fall omtrent 11 dager[6] for et containerskip, og batteriet ville derfor vært større enn skipet. Dagens batteriteknologier vil derfor vanskelig kunne fungere for de store skipene. Grunnen er at energiinnholdet til et moderne Litium Ion (Li-ion) batteri (kWh/kg) er omtrent 50 ganger mindre enn flytende drivstoff (Curran m.fl. 2024).

Dagens batterier vil være et nisjeprodukt for mindre båter og skip for korte avstander, men batterier kan være viktige for å ta toppene av etterspørselskurven i et skip, slik at man slipper å kjøre motorer/reaktorer unødig opp og ned for å håndtere etterspørselen. Det vil redusere klimagassutslipp, vedlikehold og kostnader.

Biodrivstoff

Når det gjelder biodrivstoff, er det viktig å skille mellom de biodrivstoffene som er produsert fra nytt materiale, som er langt fra bærekraftig (800 scientists 2018), og biodrivstoff som er produsert fra biologisk avfall. Med den økende konkurransen om et endelig areal med land (Fairley 2022) vil dette bli vanskeligere og vanskeligere å gjøre på en bærekraftig måte. Problemet er skala og kostnader (Kass m.fl. 2018); biodrivstoff til shipping vil kreve svært mye landareal med ditto store kostnader for transport og alternative bruk av landarealet. Elektrisiteten som trengs for å produsere biodrivstoffet fra biomassen kommer i tillegg, og akkurat som for batterier, vil sannsynligvis biodrivstoff forbli et nisjeprodukt.

Kjernekraft som løsning for maritim industri

Effekttetthet har alltid vært driveren bak utvikling (Smil 2016), og det neste stoppet på stigen er kjernekraft. Kjernekraft har også fordelen av man kan produsere store mengder restvarme som kan brukes til blant annet produksjon av biodrivstoff – om man har nok biologisk avfall. For shipping har de tradisjonelle lettvannreaktorene noen mindre ønskelige forhold (Schøyen og Steger-Jensen 2017), mens noen nye Generasjon IV reaktorteknologier virker lovende (Emblemsvåg 2021). Forskning på kjernekraft til ulike formål vil derfor sannsynligvis være viktig for å løse utfordringene som sjøfartsnæringen står overfor.

Konklusjon

Produksjon av grønne drivstoff er svært energikrevende, selv om vi begrenser oss til nasjonale forhold og Norge ikke tar ansvar for sin andel av den globale handelsflåten. Det vil kreve en helt annen satsing enn i dag på energiproduksjon om grønne drivstoff skal kunne bli en realitet på en skala som betyr noe for klimagassutslippene til shipping. Analysen i denne artikkelen er begrenset til energiregnestykket og tar ikke høyde for andre faktorer, slik som energisikkerhet, sysselsetting og andre faktorer som er viktige for et land eller en industri.

Slik situasjonen står nå, mener forfatteren at kjernefysisk fremdrift på skip til å være den eneste farbare veien for større skip, mens for de mindre skipene kan produksjon av ulike drivstoff på land være mulig å få til om man har nok overskuddsenergi på land fra kontrollerbare energikilder.

6 Transitt-tider kan fås fra https://ss.shipmentlink.com/tvs2/jsp/TVS2_InteractiveSchedule.jsp.

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Journal of
Marine Science and Engineering

MDPI

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A Study on the Limitations of Green Alternative Fuels in Global Shipping in the Foreseeable Future

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Abstract: Shipping carries over 80% of global trade volumes and emits 3% of global greenhouse gas emissions, but it is hard to abate due to the simple fact that ships require a lot of energy and move around. Therefore, a large amount of research and development is poured into understanding the choices of alternative fuels and developing new technologies. Unfortunately, much of the work and policies derived, therefore, seem to rest on a hidden assumption that a relevant amount of green alternative fuel will be available, but that assumption does not stand up to scrutiny on a global level. For example, the results show that decarbonizing global shipping using green ammonia produced from renewable energy sources will require 3.7 times the total EU-27 power production in 2022. The purpose and novelty of this paper are to offer a clear rationale for the correct contextualization of research and development on curbing greenhouse gas emissions from global shipping and individual shipping segments to avoid overpromising and underdelivering.

Keywords: batteries; biofuels; gravimetric energy density; green ammonia; green methanol; green hydrogen; nuclear

Academic Editors: Livia Maglić, Lovro Maglić, Ana Peric Hadzic, Marina Zanne and Nam Kyu Park

Received: 15 December 2024
Revised: 2 January 2025
Accepted: 4 January 2025
Published: 5 January 2025

Citation: Emblemsvåg, J. A Study on the Limitations of Green Alternative Fuels in Global Shipping in the Foreseeable Future. *J. Mar. Sci. Eng.* **2025**, *13*, 79. https://doi.org/10.3390/jmse13010079

1. Introduction

Shipping carries over 80% of global trade volume [1] and emits about 3% of the total global greenhouse gas (GHG) emissions, or slightly above the GHG emissions of Germany as a whole country [2]. Without any effective countermeasures, the share is expected to grow to 10–13% [3].

The challenge with ships is that they move and consume large quantities of energy, and batteries are not relevant. Large ships require about 3000 MWh per day on average [4], which is on par with the largest grid battery in the world (Moss Landing Energy Storage Facility) with its 3000 MWh capacity [5]. In fact, a state-of-the-art Lithium Ion (Li-ion) battery's energy content (kWh/kg) is approximately 50 times smaller than that of liquid fossil fuels [6]. Therefore, batteries are only relevant for short distances. However, batteries can serve as an excellent technology for peak-shaving, thus reducing the load variations on main and auxiliary machinery, resulting in subsequent lower GHG emissions and operating costs.

Therefore, the focus is currently on alternative fuels in shipping. The term 'alternative fuels', however, is not unambiguously defined. The DNV Alternative Fuels Insight online platform is useful because it published actual commercial activities, and in the first 11 months of 2024, it has logged 252 ships contracted using LNG, 47 using LPG, 162 using methanol, 23 using ammonia, and only 7 using hydrogen. Out of these, hydrogen, ammonia, and methanol have very low life-cycle GHG emissions and, therefore, constitute the foci of this paper.

Green ammonia is produced as 100% renewable and carbon-free by using hydrogen from water electrolysis and nitrogen separated from the air, which is subsequently fed into the Haber–Bosch process, all powered by sustainable electricity [7]. "There is a strong focus on [green] ammonia as a possible alternative to fossil carbon fuel for propulsion", according to Andrea Pestarino at the Engimmonia project [3]. Furthermore, he estimates that "[green] Ammonia is currently seen as the most efficient way to decarbonize the shipping sector, especially propulsion". This view is shared by most, and "The alternative energy fuels most suited for international shipping are primarily advanced biofuels and e-fuels (i.e., synthetic fuels), namely methanol and ammonia" [1].

Green methanol is produced from methanol from renewable electricity (e-methanol) and captured carbon dioxide [8] reducing the GHG emissions by 59% in comparison to the conventional processes [9] and, therefore, within the climate targets set forth by IMO [10] for the next decades. Conceptually, renewable electricity is used to produce green compressed hydrogen by water electrolysis, whereas CO_2 can be captured from concentrated sources (e.g., flue gas from power generation or industrial plants) or directly from air. In the remainder of this paper, green hydrogen is understood as green compressed hydrogen at 350 bar pressure.

Biofuels are also green alternative fuels, but it is critical to distinguish between biofuels produced using virgin biomass, which is far from sustainable [11], and biofuels using genuine biological waste. The ultimate dilemma regarding biofuel is, therefore, the intensified competition for finite land [12]. Basically, a key barrier for biofuels at relevant scales is the lack of sufficient quantities of some biofuels for large-scale experimentation and costs [13].

The purpose of this paper is to address the fact that the production of these green alternative fuels is taken for granted; see, for example, [6], which has written an otherwise excellent paper. In fact, all technologies that use hydrogen have additional major practical challenges [14]; although, green methanol has a major benefit over the other green alternative fuels in that the current install base of engines can be used with only minor changes. The availability of green alternative fuels at scale is also taken for granted in policy documents, such as in the UK [15] and IMO [16]. There are also papers, reports, and books that do not discuss fuel availability at all.

Despite the importance of fuel availability in addressing the climate goals set forth by IMO [10], there are very few documents addressing the availability of green alternative fuels. The excellent study of [17] is an exemption, but it does not model the global fleet and how large the demand for green alternative fuels will become. Another interesting study [18] considerably underestimates the amount of fuel consumed by shipping globally, but it reaches a similar conclusion as this paper in that the required amount of electricity from renewable energy sources is prohibitively large (5500 TWh/year). This report to the IMO has unfortunately not been taken into account in any IMO policies, as far as this author observes. Neither of the two aforementioned studies are peer-reviewed.

The purpose of this paper is, therefore, to research the availability of green alternative fuels to better understand the implications of scaling these fuels to a global level and question the assumption that green alternative fuels will be available. Furthermore, it will become the first peer-reviewed study on the topic. The novelty of this paper is to discuss the availability of green alternative fuels explicitly, on a correct global scale, taking into account all major fossil fuels used by shipping. Obtaining a correct scale is necessary to understand the decarbonization challenge. This paper will also break the results down into the different shipping segments to provide additional understanding. Finally, this study provides a correct contextualization for research and development, including exemplifying niches where green alternative fuels can succeed at a useful scale.

This study has a narrow scope, focusing only on fuel availability to ensure that this crucial aspect of decarbonizing shipping receives the attention it deserves. There is no doubt, however, that cost analyses are also required to obtain a complete picture of green alternative fuels, particularly given the importance of shipping in the world economy. Unfortunately, cost analyses in the literature are far from converging towards any consensus, and including them in this paper would be a major undertaking in itself, requiring a full review and additional analyses. Cost analyses are, therefore, future work.

In the next section, the method is discussed followed by analysis and results in Section 3. The discussion in Section 4 will also briefly mention aviation and other solutions before the conclusion is presented in Section 5.

2. Materials and Methods

The method is straightforward and consists of five steps, which are explained in the subsequent sections. The first step is to obtain the necessary input data from the literature, which is split into two separate sections for clarity.

2.1. Step 1A—Estimate the Total Fossil Fuel Consumed by Shipping in 2022

First, the fuel requirements of today's global shipping are identified from the literature, using 2022 as a reference year. The dataset [19] of fossil fuel consumption has an overall best fit with other literature sources. The data set is from 2012 and must be updated. The data set can be updated by using the annual growth in tonnage from 2011 to 2022, which is 4.9% [1]. However, the growth of tonnage is not necessarily the same as growth in fuel consumption. For example, focusing on the Heavy Fuel Oil (HFO) segment only, the estimated HFO consumption in 2022 would be more than 50 million tonnes (Mtonnes) higher than we find in other sources. Therefore, to stay on the conservative side, 300 Mtonnes HFO [20] are used to scale the data of [19] from 2012 to 2022. The result is an increased fuel consumption of 32% across all fossil fuel categories, assuming a constant mix; see Figure 1. The data of [14,21] are almost in full agreement—only a deviation of 1.8% on HFO for which they both provide data.

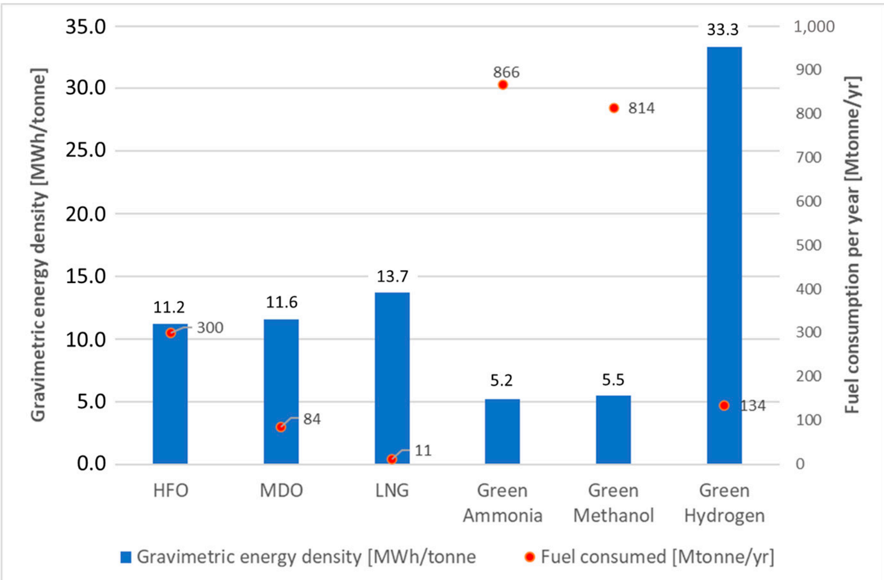

Figure 1. Gravimetric energy density [MWh/tonne] of fuels and the amount of green alternative fuel [Mtonne/yr] that corresponds to the same amount of energy to shipping as the three fossil fuels (HFO, MDO, and LNG) in 2022. Authors fuel calculations based on data from [14,19–21].

2.2. Step 1B—Obtain the Gravimetric Energy Density of the Respective Fossil Fuels

To convert fossil fuels to the energy-equivalent amount of green alternative fuels, gravimetric energy density data are used; see Figure 1. These data are based on physiochemical properties, but measuring them can introduce some uncertainties; see [17].

Note that such physiochemical properties are not subject to innovation or anything—just as little as gravity is. 'Gravimetric energy density' is not the same as 'volumetric energy density' [22]. Gravimetric energy density is the energy available per unit mass [Joule/kg or MWh/kg] and is often referred to as 'specific energy', whereas volumetric energy density is what a physicist will refer to as 'energy density' and is measured as the amount of energy per unit volume [Joule/m^3 or MWh/m^3]. Volumetric and gravimetric energy densities are therefore related through the density of the substance [kg/m^3], which may vary for some substances according to temperature and pressure, see for example [23], making quantification difficult under certain circumstances that are not relevant here. Note that power density is essentially the instantaneous gravimetric energy density focusing on effect (power) and not energy (power over time).

2.3. Step 2—Estimate the Energy Equivalent Amount of Green Alternative Fuels Using the Gravimetric Energy Density of the Respective Fossil Fuels

By assuming that the ships will operate as today, the amount of fossil fuels can be converted into the energy equivalent amount of green ammonia, green methanol, and green hydrogen by using the gravimetric energy density data found in Figure 1. Using the axis to the right in Figure 1, we see that 866 Mtonnes of green ammonia, 814 Mtonnes of green methanol, or 134 Mtonnes of hydrogen will produce the same amount of energy as the 395 Mtonnes of fossil fuels (300 Mtonnes HFO, 84 Mtonnes MDO, and 11 Mtonnes LNG).

2.4. Step 3—Estimate the Amount of Electricity Required to Produce the Green Alternative Fuels

The production of green alternative fuels will require a certain amount of specific electricity, as shown in Figure 2. For simplicity, it is assumed that there are no losses in transmissions, grid bottlenecks, or the like concerning the electricity used in the production of green alternative fuels. This is, of course, a convenient assumption, but it also results in a conservative estimate. For example, in Norway, the losses in the grid are in the order of 6–7%.

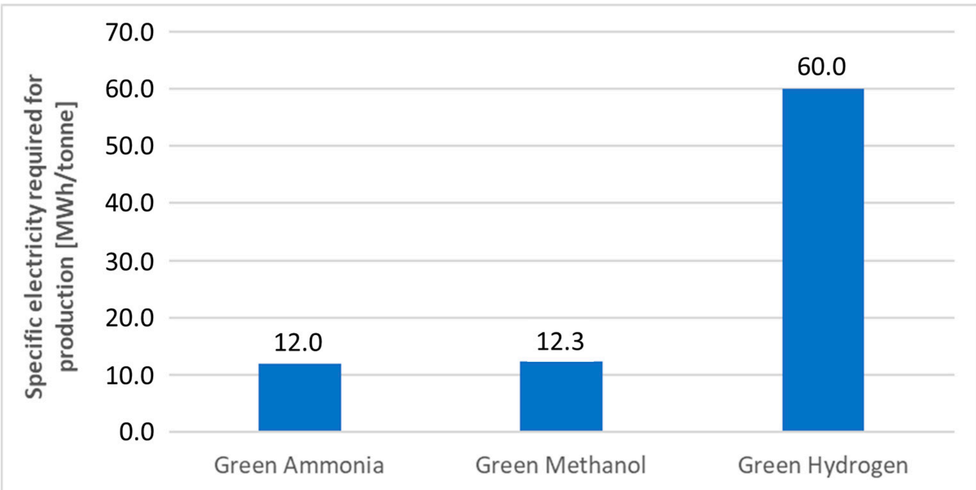

Figure 2. Specific electricity [MWh/tonne] required to make green alternative fuels. Data are from [8,14,17].

It is also assumed that variable renewable energy can be used for electrolysis because it is a common assumption in the literature—the very definitions of green alternative fuels depend on this assumption. Practically all industrial users, however, need 100% reliability, particularly for large industrial installations and energy-intensive processes [24]. A shutdown of an LNG plant, for example, creates both a safety hazard and a major loss of production, taking up to 48 h to come back online [25]. Currently, only hydroelectric power (of the renewable energy types) is used for large industrial facilities. Therefore, using variable renewable energy is a questionable assumption.

Note that the exact technologies used in the conversion processes behind the steps discussed will introduce some uncertainties in both the production and demand for green alternative fuels. Hence, the estimates probably have an accuracy of ±10%, which is accurate enough given the overall conclusion.

The renewable electricity required (RER) per year to produce a certain amount of green alternative fuel (GAF) can be calculated from Equation (1) by multiplying the fossil fuel consumption (FFC) by the corresponding gravimetric energy density (GED) and dividing the sum of all fossil fuels (HFO, MDO and LNG) by the gravimetric energy density (GED) of the green alternative fuel in question and multiply it by its specific electricity (SE) requirement in production:

$$RER_{GAF\ n} = \frac{\sum_{All\ fossil\ fuels} FFC_{Fossil\ fuel\ n} * GED_{Fossil\ fuel\ n}}{GED_{GAF\ n}} * SE_{GAF\ n} \tag{1}$$

2.5. Step 4—Compare Results to a Known Entity to Make a Compelling Argument

Understanding large numbers is difficult, and to make a compelling comparison, in order to help people understand the scale, data for major countries and continents are used. The challenge with such data is that there are often minor discrepancies. For example, while the total EU-27 electricity production in 2022 was 2641 TWh [26], the same figure from OurWorldInData is 2812 TWh or 6.5% higher. Such smaller differences are common, but they do not influence the overall conclusion.

2.6. Step 5—Break Results Down into Different Ship Segments for Better Understanding

Finally, different ship segments are analyzed using data from [6], assuming that the shipping segment mix is constant, as noted earlier. By understanding the different shipping segments better, more suitable solutions can arguably be found, and research and development can be better contextualized.

3. Results

The electricity required to produce green alternative fuels is shown in Figure 3. Green ammonia and green methanol will require more than 10,000 TWh/yr of available electricity. The suitability of these fuels for shipping, as argued by [1], is therefore highly questionable due to the scale of the available electricity required. Green hydrogen comes out somewhat better, but not enough to make a material difference.

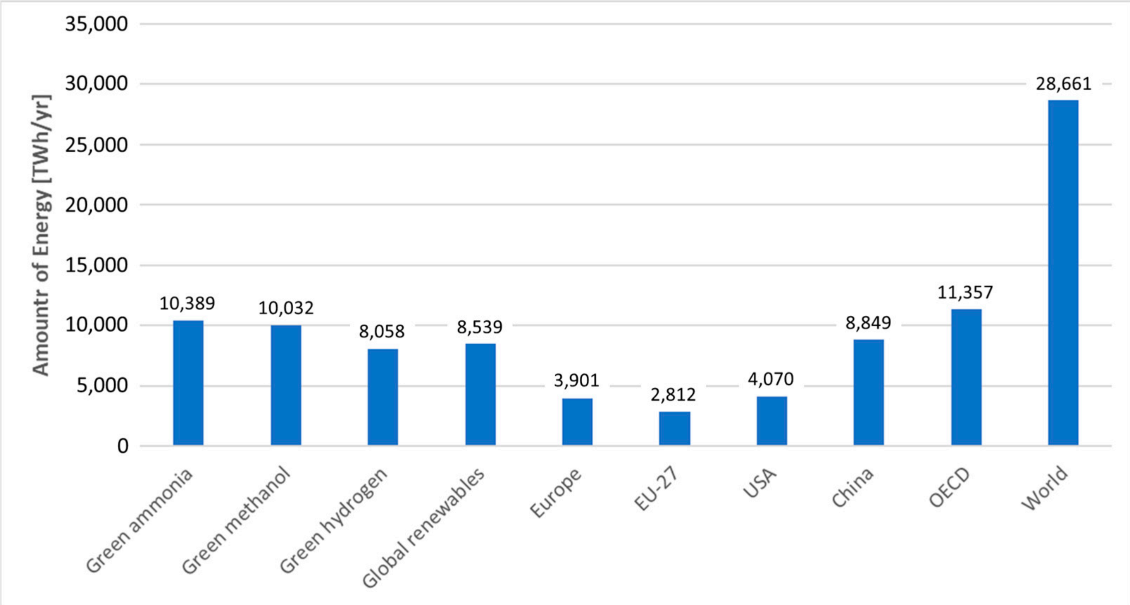

Figure 3. The electricity requirement of decarbonizing shipping [TWh/yr] compared to large geographical entities. Note that renewable energy in the figure also includes hydro.

Some context is beneficial to help us understand the scale; see Figure 3. Of all the major industrial entities on the planet, only the entire world or the entire Organization of Economic Cooperation and Development (OECD) will have enough electricity supply but at the expense of other electricity users. If we include losses, shipping would essentially need all the electricity in the OECD in 2022, which is mostly fossil.

There are currently 38 OECD member countries: Australia, Austria, Belgium, Canada, Chile, Colombia, Costa Rica, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, South Korea, Latvia, Lithuania, Luxembourg, Mexico, The Netherlands, New Zealand, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Türkiye, United Kingdom, and the United States of America.

Some more details may be helpful in better targeting decarbonization approaches. The results per shipping segment are shown in Tables 1–3. Evidently, the large shipping segments, such as container ships, will require as much electricity as the entire EU-27; see Figure 3. Even the smallest segments, such as offshore vessels, will require more than half of Germany's electricity generation, which in 2022 was 561 TWh.

Another interesting observation is that about 2.3 times more electric power is necessary to replace fossil fuels on average, and this is because of all the losses in converting electric power into green alternative fuels. In total, 57% of the energy is lost, whereas a large two-stroke engine with heat recovery can give a peak thermal efficiency of 60–65% [6]. There are additional losses in the supply chain for all alternatives.

Table 1. Green ammonia results per ship segments. Authors calculations using the data above and the segmentation from [6]. Overall power conversion loss ratio is found by dividing grand total electricity amount by energy content in the fossil fuels, and for green ammonia, it becomes 2.3 times, which implies 57% losses. Author's calculations.

Technology	Ship Segment		Fuel	Amount per Year		Energy Content per Year		Equivalent Green Ammonia Amount per Year		Electricity Required for Production per Year	
Two-stroke	Container ships	22%	HFO	87	Mtonnes/yr	971	TWh(th)/yr	188	Mtonnes/yr	2256	TWh(e)/yr
engine	Bulk carriers	18%	HFO	71	Mtonnes/yr	794	TWh(th)/yr	154	Mtonnes/yr	1848	TWh(e)/yr
	Oil tankers	13%	HFO	51	Mtonnes/yr	574	TWh(th)/yr	111	Mtonnes/yr	1332	TWh(e)/yr
	General cargo	7%	HFO	28	Mtonnes/yr	309	TWh(th)/yr	60	Mtonnes/yr	720	TWh(e)/yr
	Chemical tankers	6%	HFO	24	Mtonnes/yr	265	TWh(th)/yr	51	Mtonnes/yr	612	TWh(e)/yr
	TOTAL	**66%**		**261**	**Mtonnes/yr**	**2912**	**TWh(th)/yr**	**564**	**Mtonnes/yr**	**6768**	**TWh(e)/yr**
Four-stroke	Offshore	3%	MDO	12	Mtonnes/yr	137	TWh(th)/yr	27	Mtonnes/yr	324	TWh(e)/yr
engine	Vehicle	3%	MDO	12	Mtonnes/yr	137	TWh(th)/yr	27	Mtonnes/yr	324	TWh(e)/yr
	Cruise	4%	HFO	16	Mtonnes/yr	176	TWh(th)/yr	34	Mtonnes/yr	408	TWh(e)/yr
	Fishing	5%	MDO	20	Mtonnes/yr	229	TWh(th)/yr	44	Mtonnes/yr	528	TWh(e)/yr
	LNG tankers	5%	LNG	20	Mtonnes/yr	271	TWh(th)/yr	53	Mtonnes/yr	636	TWh(e)/yr
	RoRo/RoPax	6%	HFO	24	Mtonnes/yr	265	TWh(th)/yr	51	Mtonnes/yr	612	TWh(e)/yr
	All other	8%	MDO	32	Mtonnes/yr	366	TWh(th)/yr	71	Mtonnes/yr	852	TWh(e)/yr
	TOTAL	**34%**		**134**	**Mtonnes/yr**	**1583**	**TWh(th)/yr**	**307**	**Mtonnes/yr**	**3684**	**TWh(e)/yr**
	Grand TOTAL	**100%**		**395**	**Mtonnes/yr**	**4495**	**TWh(th)/yr**	**871**	**Mtonnes/yr**	**10,452**	**TWh(e)/yr**

Table 2. Green methanol results per ship segments. Authors calculations using the data above and the segmentation from [6]. Overall power conversion loss ratio is 2.2 times, which implies 55% losses. Author's calculations.

Technology	Ship Segment		Fuel	Amount per Year		Energy Content per Year		Equivalent Green Methanol Amount per Year		Electricity Required for Production per Year	
Two-stroke	Container ships	22%	HFO	87	Mtonnes/yr	971	TWh(th)/yr	176	Mtonnes/yr	2170	TWh(e)/yr
engine	Bulk carriers	18%	HFO	71	Mtonnes/yr	794	TWh(th)/yr	144	Mtonnes/yr	1775	TWh(e)/yr
	Oil tankers	13%	HFO	51	Mtonnes/yr	574	TWh(th)/yr	104	Mtonnes/yr	1282	TWh(e)/yr
	General cargo	7%	HFO	28	Mtonnes/yr	309	TWh(th)/yr	56	Mtonnes/yr	690	TWh(e)/yr
	Chemical tankers	6%	HFO	24	Mtonnes/yr	265	TWh(th)/yr	48	Mtonnes/yr	592	TWh(e)/yr
	TOTAL	**66%**		**261**	**Mtonnes/yr**	**2912**	**TWh(th)/yr**	**528**	**Mtonnes/yr**	**6509**	**TWh(e)/yr**
Four-stroke	Offshore	3%	MDO	12	Mtonnes/yr	137	TWh(th)/yr	25	Mtonnes/yr	308	TWh(e)/yr
engine	Vehicle	3%	MDO	12	Mtonnes/yr	137	TWh(th)/yr	25	Mtonnes/yr	308	TWh(e)/yr
	Cruise	4%	HFO	16	Mtonnes/yr	176	TWh(th)/yr	32	Mtonnes/yr	394	TWh(e)/yr
	Fishing	5%	MDO	20	Mtonnes/yr	229	TWh(th)/yr	42	Mtonnes/yr	518	TWh(e)/yr
	LNG tankers	5%	LNG	20	Mtonnes/yr	271	TWh(th)/yr	49	Mtonnes/yr	604	TWh(e)/yr
	RoRo/RoPax	6%	HFO	24	Mtonnes/yr	265	TWh(th)/yr	48	Mtonnes/yr	592	TWh(e)/yr
	All other	8%	MDO	32	Mtonnes/yr	366	TWh(th)/yr	67	Mtonnes/yr	826	TWh(e)/yr
	TOTAL	**34%**		**134**	**Mtonnes/yr**	**1583**	**TWh(th)/yr**	**288**	**Mtonnes/yr**	**3550**	**TWh(e)/yr**
	Grand TOTAL	**100%**		**395**	**Mtonnes/yr**	**4495**	**TWh(th)/yr**	**816**	**Mtonnes/yr**	**10,059**	**TWh(e)/yr**

Table 3. Green hydrogen results per ship segments. Authors calculations using the data above and the segmentation from [6]. Overall power conversion loss ratio is 1.8 times, which implies 44% losses. Author's calculations.

Technology	Ship Segment		Fuel	Amount per Year		Energy Content per Year		Equivalent Green Hydrogen Amount per Year		Electricity Required for Production per Year	
Two-stroke	Container ships	22%	HFO	87	Mtonnes/yr	971	TWh(th)/yr	29	Mtonnes/yr	1740	TWh(e)/yr
engine	Bulk carriers	18%	HFO	71	Mtonnes/yr	794	TWh(th)/yr	24	Mtonnes/yr	1440	TWh(e)/yr
	Oil tankers	13%	HFO	51	Mtonnes/yr	574	TWh(th)/yr	17	Mtonnes/yr	1020	TWh(e)/yr
	General cargo	7%	HFO	28	Mtonnes/yr	309	TWh(th)/yr	9	Mtonnes/yr	540	TWh(e)/yr
	Chemical tankers	6%	HFO	24	Mtonnes/yr	265	TWh(th)/yr	8	Mtonnes/yr	480	TWh(e)/yr
	TOTAL	**66%**		**261**	**Mtonnes/yr**	**2912**	**TWh(th)/yr**	**87**	**Mtonnes/yr**	**5220**	**TWh(e)/yr**
Four-stroke	Offshore	3%	MDO	12	Mtonnes/yr	137	TWh(th)/yr	4	Mtonnes/yr	240	TWh(e)/yr
engine	Vehicle	3%	MDO	12	Mtonnes/yr	137	TWh(th)/yr	4	Mtonnes/yr	240	TWh(e)/yr
	Cruise	4%	HFO	16	Mtonnes/yr	176	TWh(th)/yr	5	Mtonnes/yr	300	TWh(e)/yr
	Fishing	5%	MDO	20	Mtonnes/yr	229	TWh(th)/yr	7	Mtonnes/yr	420	TWh(e)/yr
	LNG tankers	5%	LNG	20	Mtonnes/yr	271	TWh(th)/yr	8	Mtonnes/yr	480	TWh(e)/yr
	RoRo/RoPax	6%	HFO	24	Mtonnes/yr	265	TWh(th)/yr	8	Mtonnes/yr	480	TWh(e)/yr
	All other	8%	MDO	32	Mtonnes/yr	366	TWh(th)/yr	11	Mtonnes/yr	660	TWh(e)/yr
	TOTAL	**34%**		**134**	**Mtonnes/yr**	**1583**	**TWh(th)/yr**	**47**	**Mtonnes/yr**	**2820**	**TWh(e)/yr**
	Grand TOTAL	**100%**		**395**	**Mtonnes/yr**	**4495**	**TWh(th)/yr**	**134**	**Mtonnes/yr**	**8040**	**TWh(e)/yr**

The key results in Table 1 for green ammonia are shown in Figure 4 for easier comparison. The green methanol and green hydrogen results are very similar. Green hydrogen requires about 20% less electricity than the two other green alternative fuels. This would help, of course, but the sheer amount is still as high as all of the Chinese electricity production that the conclusion becomes materially the same, i.e., that there is insufficient amount of renewable electricity to produce the green alternative fuels.

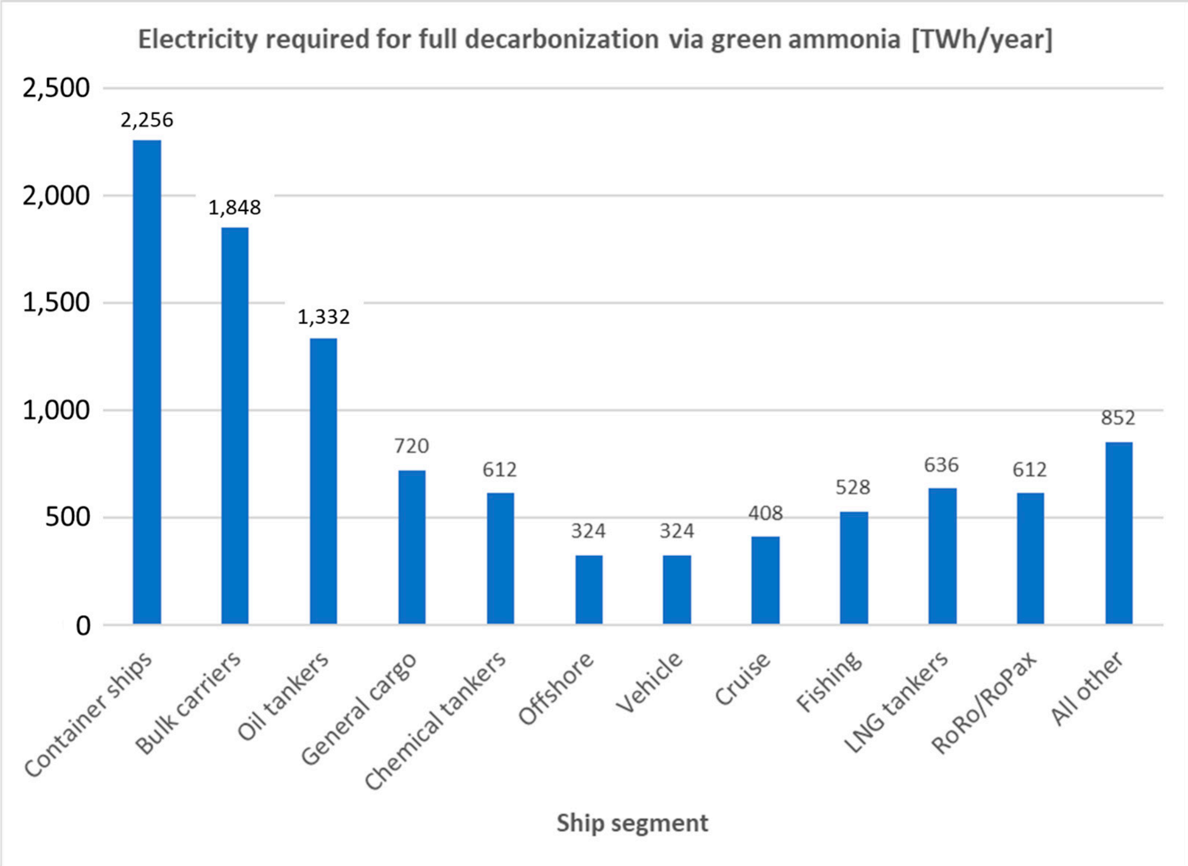

Figure 4. Electricity required globally to provide green ammonia for all shipping segments.

Note that

- TWh(th) is the unit of the useful part of the thermal energy produced by the engine that results in work being done.
- TWh(e) is the electrical energy used to produce the amount of green alternative fuel that will deliver the equivalent amount of work.

Due to the fact that even the smallest shipping segments are too large to fully supply green alternative fuels, a different approach is required, as discussed in Section 4.

4. Discussion

The presented analysis has one major uncertainty that noticeably impacts the result—the uncertainty of the electricity required to produce green alternative fuels. The literature is not conclusive. The current mid-range estimates for the electricity requirements are therefore used as the best approximation.

To validate the results and prove their robustness, an uncertainty analysis using Monte Carlo simulations of the model is performed, where all parameters are modeled as triangular uncertainty distributions with ±10%, except the electricity required for producing green alternative fuels, where the uncertainty in the literature is ±20%. See [27] for details about how to conduct such analyses and the usage of triangular uncertainty distribution. The results are shown in Figure 5 for the green alternative fuels discussed here.

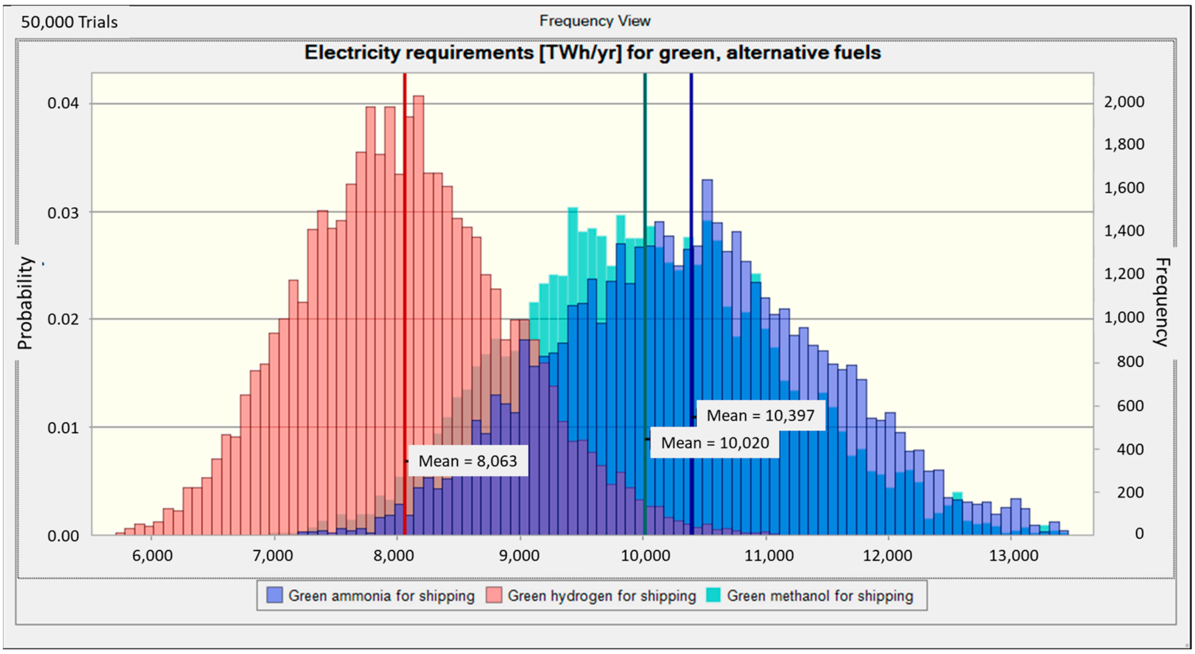

Figure 5. Electricity [TWh/yr] required globally to provide green ammonia for all shipping segments where actual data uncertainties are included.

With the inherent conservatism of the analysis, the overall conclusion stands irrespectively because the estimated electricity requirements are so large that the amount of renewable electricity required to produce green alternative fuels is far beyond the current power system capabilities. Thus, the conclusion is robust beyond any uncertainties.

Given that humanity has spent more than 100 years developing the current power system, the time horizon discussed here becomes beyond the foreseeable future and probably also beyond 2100. Thus, fresh thinking is required with more realistic contextualization concerning the availability of green alternative fuels.

For completeness, it is also useful to discuss two related topics that are frequently mentioned in the same context: (1) aviation as another example of a hard-to-abate industry, and (2) a possible solution before we discuss how to improve the contextualization of research and development in Section 4.3.

4.1. Green Alternative Fuels for Aviation

The annual jet fuel consumption of 220 Mtonnes [28] and the overall demand is expected to grow. The higher gravimetric energy density of jet fuel compared to HFO indicates that replacing the 220 Mtonnes of jet fuel with green alternative fuels will require more renewable electric power than the same amount of HFO. Thus, if we add aviation to the same discussion, providing green alternative fuel from renewable energy sources will worsen the situation considerably. In fact, we are talking more or less about a doubling to almost 20,000 TWh/yr.

4.2. A Possible Solution

Power density (the time derivative of energy density) has always been a key driver of development [29], and the next step on the gravimetric energy density ladder is nuclear power. For shipping, the traditional light water reactor technologies have issues [30], but some Generation IV reactor technologies have promising results [31]. Researching nuclear propulsion is, therefore, a possible avenue for the future of maritime transport, particularly for large ships that arguably have no green alternative fuel options in sight.

Nuclear power has the additional benefit of producing thermal rest energy that can be used for biofuel production and significantly improve the energy calculations of biofuel for a given availability of sustainably gathered biomass. Furthermore, nuclear can also produce alternative fuels directly that can be used for smaller ships and aviation.

4.3. How to Improve the Contextualization of Research and Development

The results show conclusively that a relevant supply of green alternative fuels for shipping as an industry is beyond the capabilities of the current power system, even beyond the foreseeable future. However, this conclusion does not necessarily include small ships such as ferries, fishing vessels, and the like that fall under the 'All other' category in Figure 4 for local and mostly domestic shipping.

For example, a similar analysis shows that replacing the 1.15 Mtonnes of MDO consumed by domestic shipping in Norway will require 31 TWh/year of electricity or 23% of the total hydroelectric power production in Norway [32]. Thus, supplying domestic shipping in Norway with green alternative fuels, with a moderate expansion of the power system, is arguably possible.

The keyword of [32] is 'domestic'. Domestic shipping has, per definition, much shorter routes, thereby reducing the amount of fuel that must be carried along while in transit. Therefore, unlike international shipping, domestic shipping can utilize green alternative fuels by expanding the land-based infrastructure provided that there is a sufficient amount of renewable electricity available. Hydroelectric power is critical in this context to maintain production without safety-related production interruptions, as discussed earlier. Whether or not hydroelectric power is used for applications with such high conversion losses is another question that is outside the scope of the discussion here.

Clearly, research and development of technologies and development of policies must make a conscious choice concerning the availability of green alternative fuels. Basically, the availability of green alternative fuels cannot be taken for granted. There are, however, niches in shipping where a supply of green alternative fuels is possible, as discussed. In the grand scheme of the global shipping industry, however, the relevant scaling of green alternative fuels is practically impossible due to the power system constraints today and well beyond the foreseeable future. Therefore, the availability of green alternative fuels should become an important reality check for all research and development aiming at decarbonizing hard-to-abate industries such as shipping and aviation.

5. Conclusions

This paper has presented some basic realities of replacing fossil fuels in shipping with green alternative fuels for the same amount of work being performed. The required amount of electric power for producing these green alternative fuels is subsequently calculated. Compared on a scale equal to major industrial entities globally, it is proven beyond any doubt that there is basically not enough electricity in the world to make a relevant amount of green alternative fuels for shipping.

Basically, the gravimetric energy densities are orders of magnitude too low, or the thermodynamical losses are too high, for electricity to replace fossil fuel in this particular application. This finding also questions the conventional wisdom of the merit of an all-encompassing electrification of society. There are, however, niches where a relevant supply of green alternative fuels is possible to secure, albeit difficult.

Therefore, much of today's research on green alternative fuels rests on a hidden assumption—that there will be available fuels. However, green alternative fuels will not be available in relevant quantities unless the research is well contextualized for small ships on short, domestic distances. The fuel availability is, therefore, a key constraint to incorporate in future work on green alternative fuels for shipping.

Furthermore, it seems prudent to open up a wider search for solutions, including nuclear propulsion, based on the fact that the gravimetric energy densities are physical realities that we must respect. The wise words of St. Francis of Assisi come to mind:

> *Lord, grant me the strength to accept things I cannot change, the courage to change the things I can, and the wisdom to know the difference.*

Funding: This research received no external funding including the APC.

Institutional Review Board Statement: The author has attempted to the best of his abilities to abide by the ethical guidelines for authors provided by the publisher.

Informed Consent Statement: Not applicable.

Data Availability Statement: The original contributions presented in this study are included in the article. Further inquiries can be directed to the corresponding author.

Acknowledgments: The author would like to thank the reviewers and the guest editor for providing very detailed and useful feedback which has essentially resulted in the paper as presented.

Conflicts of Interest: The author declares that there are no conflicts of interest.

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Proceedings of the ASME 2024
2024 31st International Conference on Nuclear Engineering (ICONE31)
August 4-8, 2024, Prague, The Czech Republic

ICONE31-135177

CRITERIA FOR SELECTING NUCLEAR REACTORS FOR MERCHANT SHIPPING

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ABSTRACT

The Deep-Sea Fleet consumes about 300 million tonnes of Heavy Fuel Oil (HFO) annually and emits 3% of global greenhouse gas emissions. Currently, green ammonia is seen as the most promising zero-emission substitute. Yet, if green ammonia was to replace HFO, an equivalent to 2.7 times the total EU electricity production in 2022 would be required to produce this fuel. Therefore, the shipping industry investigates whether nuclear power can provide a viable, safe, and cost-effective solution to this challenge. Some navies have successfully used small Light Water Reactors for decades, but studies identify many challenges including costs and public acceptance related to use of such reactors in merchant ships. However, one study demonstrates that for an AfraMax size tanker, the life-cycle cost savings are expected to be 65-70 million US dollars by using a denatured Molten Salt Reactor assuming that the publicly available information is realistic. With over 80 different reactor concepts identified by yearend 2022 primarily from IAEA's Small Modular Reactor Handbook, there is a need to develop criteria that can help the shipping industry robustly identify suitable nuclear reactors. This paper presents and discusses these criteria to enable the next step in the process, the actual selection of reactor technologies for merchant shipping.

Keywords: Merchant ships, nuclear propulsion, Small Modular Reactor (SMR).

NOMENCLATURE

AfraMax tanker	Aframax refers to a class of oil tanker of medium size, larger than Panamax and smaller than Suezmax, in the range of 80,000-120,000 deadweight tonnes (DWT) with a typical draft of 14.5 – 15.5 meters.
Deep-Sea Fleet (DSF)	The large ocean-crossing ships that transport goods between continents. They run normally on HFO.
Generation IV reactor	Generation IV reactors satisfy goals in four broad areas: sustainability, economics, safety and reliability, and proliferation resistance and physical protection, see Section 1 for more information as well as [12].
Green Ammonia	Ammonia produced via renewable energy sources.
Heavy Fuel Oil (HFO)	A commonly used fuel by ships known to generate large amount of greenhouse gas emissions and particulate matter.
LNG	Liquid Natural Gas – natural gas in liquified state to enable transportation.
Mini-Fuji MSR	A specific molten-salt reactor concept from Japan. For more information see https://aris.iaea.org/PDF/MSR-FUJI.pdf
MUSD	Million US dollars.
MWe	The electric power output of a reactor expressed in megawatts (MW). It is typically about a third of the thermal power.
MWth	The thermal power output of a reactor expressed in megawatts (MW).
Short-Sea Shipping	The ships moving goods between countries within a continent. They normally run on lighter fossil fuels than HFO.
Small Modular Reactor (SMR)	SMRs are advanced nuclear reactors that have a power capacity of up to 300 MW(e) per unit [16].
TRISO fuel	TRi-structural ISOtropic particle fuel. Each TRISO particle is made up of a uranium, carbon and oxygen fuel kernel. The kernel is encapsulated by three layers of carbon- and ceramic-based materials that prevent the release of radioactive fission products [6].

1. INTRODUCTION

Shipping industry is responsible for about 3% of the total global greenhouse gas emissions [19]. This amounts to slightly above the emissions of Germany as a whole country [21]. Indeed, without any effective countermeasures, international shipping is expected to reach 10 to 13% of the global greenhouse gas emissions within two or three decades [19].

The large ships where nuclear power can conceivably be used, are commonly referred to as the Deep-Sea Fleet (DSF) or international shipping. International shipping constitutes 87% of total CO_2 emissions from all marine sources, out of which the three vessel classes 1) bulk carriers, 2) oil tankers, and 3) container vessels represent 55%. This amount is also increasing due to demand for higher speeds despite improvements in technology [21]. In addition to the three aforementioned vessel classes, large cruise ships, large special purpose ships such as cable layers and more can be included.

All in all, the shipping industry consumes approximately 300 million tonnes of Heavy Fuel Oil (HFO) annually [18], which is higher than the world's yearly jet fuel consumption of 220 million tonnes [25], and the overall demand is expected to grow. Currently, there is a strong focus on green ammonia as a possible alternative to fossil carbon fuel for propulsion [19]. Furthermore, King [19] estimates that "green ammonia is currently seen as the most efficient way to decarbonize the shipping sector, especially propulsion".

However, replacing HFO with green ammonia would annually require 7,800 TWh which would be more than 2.7 times the total EU electricity production in 2022 [9]. Another segment of the maritime sector is the "Short Sea Shipping" that operates within continental distances. These vessels are typically powered by four-stroke engines that run on different types of diesel oil. This adds to the overall emissions from the maritime sector.

Figure 1 shows a typical LNG carrier, owned and operated by Knutsen OAS (Norway), together with its key technical specifications. Nowadays, the propulsion of these LNG carriers relies on steam power cycles that are fueled by HFO boilers. Switching to nuclear propulsion will therefore involve replacing the HFO boilers with nuclear reactors. According to the shipowner, the Cadiz Knutsen ship typically consumes almost 40,000 metric tonnes HFO per year, which results in emissions of roughly 120,000 metric tonnes of CO_2 and 720 metric tons of SO_2 and a host of other minor emissions including 4 kg of Cadmium – a toxic heavy metal.

Therefore, the shipping industry needs to address the situation of high emissions from conventional fuels. Although some navies around the world have successfully used small Light Water Reactors (LWR) for decades, both this work and [22] find many challenges including costs and public acceptance application of such reactors in merchant ships. Furthermore, nuclear-powered merchant ships require special wharfs for maintenance, service and cargo operations, bringing significant challenges [27].

« Cadiz Knutsen »

Main Dimensions		**Cargo arrangement**	
Vessel type	LNG Carrier	Four (4) cargo tanks, total capacity 138 000 m^3	
Length overall	284.40 m		
Length between perp.	271.00 m	**Propulsion**	
Breadth	42.50 m	Type	Steam driven turbine
Depth to main deck	25.40 m	Power	28 000 kW
Scantling draught	12.30 m	Revolutions	83 rpm
Design draught	11.40 m		
Deadweight (design)	68 200 tns	**Main Boilers**	
Gross Tonnage	93 450 GT	2 x MHI boilers	65 000 kg/h
Service Speed	19.5 knots	Steam condition	61.8 kg/cm^2 x 515 °C

FIGURE 1: TYPICAL LNG CARRIER BEING CONSIDERED FOR CONVERSION TO NUCLEAR PROPULSION. SOURCE: KNUTSEN OAS.

Additionally, the application of nuclear convention principles to nuclear-powered merchant ships faces significant regulatory challenges, such as the ratification deadlock of specialized conventions, the inconsistent and unreliable flag states' regulation, and insufficient liability and compensation mechanisms for environmental damage indemnity [26]. However, Emblemsvåg [8] demonstrates that for an AfraMax tanker, the life-cycle cost savings are expected to be about 65-70 MUSD assuming that a denatured MSR technology, such as mini-Fuji SMR, is used, and that the publicly available information is realistic.

Nonetheless, the feasibility of adapting these reactor concepts to marine applications is unknown. Consequently, the following research question is proposed: *Are there any nuclear reactor concepts suitable for the DSF available within the next decade?* To address this question, amongst others, the Nuclear Propulsion of Merchant Shipping (NuProShip) I project was initiated and funded by the Research Council of Norway. The project aims to conduct a concept and feasibility study of marine propulsion systems for DSF, to select the most suitable reactor concepts.

To address the selection, the first step is to develop a set of criteria for the evaluation. The challenge lies in the diversity of the criteria, which leads to a classic multi-objective selection process involving both quantitative and qualitative objectives or criteria. Therefore, the selection process will be subjective with such a variety of criteria.

One of the best qualitative methods for providing decision-support in multi-objective situations, is the Analytic Hierarchy Process (AHP) that Thomas Lorie Saaty developed in the late 1960s [23]. The AHP has been used in a wide array of situations including resource allocation, scheduling, project evaluation, military strategy, forecasting, conflict resolution, political strategy, safety, financial risks, and strategic planning [24]. AHP has also been used in supplier selection [1], business performance measurement [2], quantitative construction risk management [4] and selection of maintenance strategy and organization [10].

However, applying the AHP as discussed in Section 2 can be challenging. That issue was resolved by performing an initial screening using basic exclusion criteria [10] with the purpose of bringing the complexity down to a manageable size. The resulting shortlist of reactor concepts is subsequently presented in Section 3 followed by a discussion of the future work.

2. METHOD

The method used in the NuProShip I project is the AHP. Due to the large number of reactor concepts and criteria, using AHP for this case will be labor intensive. Furthermore, collecting and verifying all the detailed information for the different reactor concepts will to some extent require the involvement of reactor vendors and access to restricted information. Therefore, as explained in this section, an initial screening is necessary.

2.1 Outline of the overall approach

The overall methodology is a decision process as shown in Figure 2. This paper will focus on the first stage, i.e., reaching some realistic alternatives. The reason for just focusing on this first step, is the simple fact that selecting among over 80 different reactor concepts with varying degree of information availability using a large set of multidimensional qualitative as well as quantitative criteria is a major job. The quality of the overall decision process hinges therefore greatly on this initial selection.

The process proposed in Figure 2 uses the well-known IDEF0 method (the template is shown in the upper right corner) for functional modelling. It is designed to model the decisions, actions, and activities of an organization or system [13]. The IDEF0 standard is maintained by the National Institute of Standards and Technology (NIST) [5].

The decision constraints in Figure 2 are essentially exclusion criteria defined as criterion whereby reactor concepts having this specific feature or characteristic are by default excluded from the overall decision process. All other criteria are matters of degree and will be determined by the AHP in Stage 2 of Figure 2. Stage 3 is the step where with the selected reactor concepts and their vendors, more alternatives to the solution space will be elicited.

2.2 The basic philosophy of the project

The challenges with international regulations are substantial and not covered in detail by this work because the solution as of today is largely unclear and unfit for purpose as far as the DSF is concerned. In other words, the concept contemplated here will be extremely difficult due to different rules in different jurisdictions. However, given that there will be a solution along the well-known proverb that 'necessity is the mother of invention', and the fact that harmonization efforts are under way [14], stringent criteria that should pre-empt such international regulations has been applied.

That being said, it is consequently a basic requirement in the selection process of nuclear reactors for marine applications that the goals as stated by the Generation IV Forum (GIF) are mostly fulfilled. Most of these ships are crossing the oceans all over the world and will have to meet the strictest safety- and performance criteria to be allowed to enter ports and shipping canals. The criteria 50% efficiency goal is relaxed because in shipping the target is to outcompete todays large, two-stroke engines running on HFO, and not necessarily designing the most efficient reactor concept.

Based on an evaluation of over 130 reactor concepts the Generation IV Forum [12] selected 6 reactor concepts for further research and development. The reactor concepts are based on advanced nuclear concepts that aim to improve the performance, safety, sustainability, and economics of nuclear power. These include the: Gas-cooled Fast Reactor (GFR), Lead-cooled Fast Reactor (LFR), Molten Salt Reactor (MSR), Supercritical Water-cooled Reactor (SCWR), Sodium-cooled Fast Reactor (SFR) and Very High Temperature Reactor (VHTR).

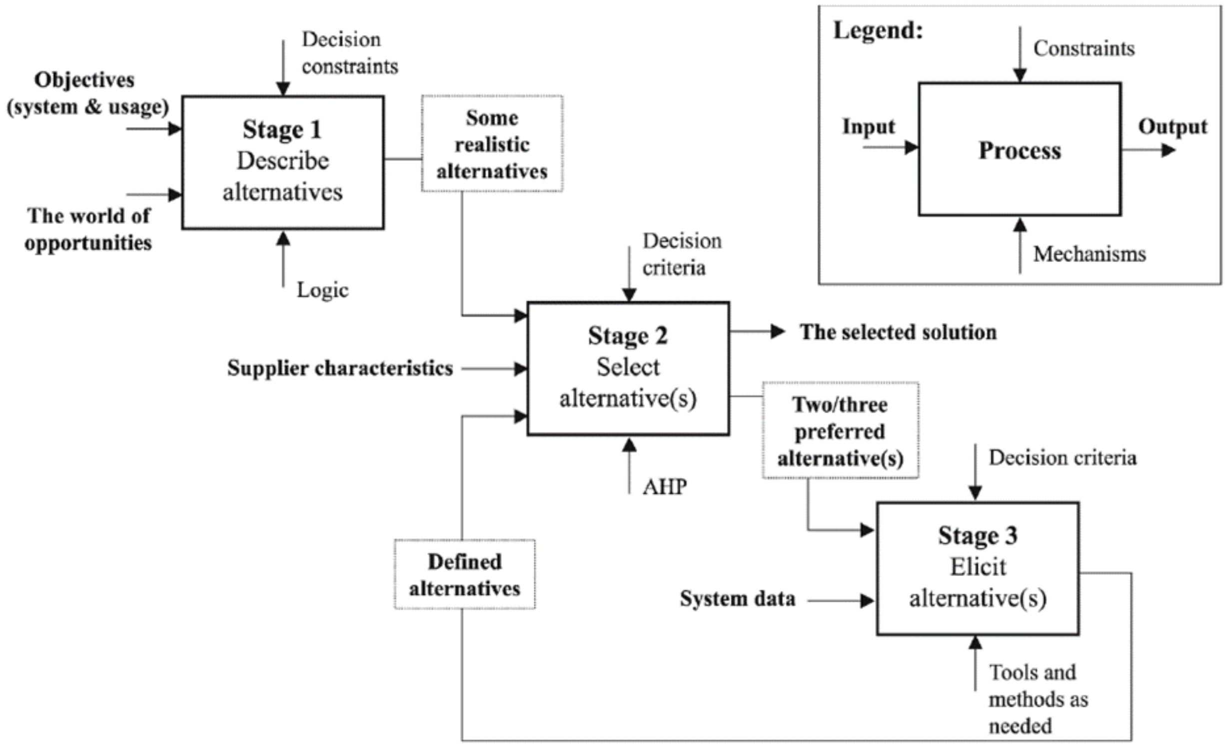

FIGURE 2: THE OVERALL SELECTION PROCESS. SOURCE: [10].

3. RESULTS AND DISCUSSION

The first step is to review the IAEA SMR Handbook [15] and the NEA SMR Dashboard [20], which together contains over 80 different reactor concepts as of yearend 2022 but may increase in number in the future. The outcome of Stage 1, see Figure 2, includes a set of realistic alternatives and the initial selection criteria for Stage 2.

In the next section, the exclusion criteria are identified for further evaluation. In Section 3.2, the shortlist of reactor concepts that meet the exclusion criteria is presented. In Section 3.3, the selection criteria based on the shortlisted concepts are introduced.

3.1 The exclusion criteria to shortlist possible useful reactor concepts

As mentioned in previous sections, the project focuses on SMR concepts. Furthermore, the exclusion criteria are based on the guidelines of the Gen IV Forum as well as its applicability for marine propulsion given the philosophy of the project. The exclusion criteria are, in no particular order:

1. Using water as coolant: Some of the reactors use water as a coolant, but we propose to exclude all water based SMRs from the analysis. The reason for this is that we think that water-based reactors will face strong public opposition, regardless of their safety performance. This is based on the observation that many people cannot differentiate between Generation III reactors and Generation III+ reactors, which have advanced safety features and impeccable records, and Generation II reactors, which were involved in major accidents such as Chernobyl and Fukushima (both accidents are greatly miscommunicated by media [3]). We expect that this negative perception will also affect water-based Generation IV SMRs. Although this may change as people become more aware of the impacts of climate change and the benefits of nuclear energy, we do not rely on that assumption. Water-based reactors will also struggle to meet the 5-year continuous operation requirement, discussed later, with an enrichment-level civilian operators will be allowed to use. Therefore, we focus on Generation IV SMRs that use alternative coolants, such as helium, molten salt, or liquid metal, which offer higher efficiency, lower waste, and enhanced safety.
2. Reliance on active safety systems: One of the main characteristics of Generation IV reactors is they rely on passive safety systems or passive shutdown systems for shutdown of the reactor including its accessories. These systems require no human action and prevent any release of radioactivity to the environment by air or water. Reactor concepts that lacked this feature or provided insufficient information about it are discarded.
3. Limited proliferation resistance: Reactor concepts with possible generation of fissile material that can be extracted and used for military purposes were excluded from further consideration. This is obviously important for ships crossing in and out of jurisdictions on frequent basis.

4. Fuel enrichment and highly toxic bi-products: Reactor concepts must require fuel enrichment below 20% of Uranium-235 and no significant Polonium 210 generation as in lead-bismuth reactors.
5. Too large power output: The thermal- and electric output should be in line with the needs for marine propulsion. For the largest oil/LNG tankers and container ships, need for power could be more than 50 MWe while for the smallest ships the requirements may go down to less than 5 MWe. Reactors of higher power output should be able to scale down with minor design changes (for example reducing the volume of the reactor vessel), otherwise they are excluded.
6. Technology is not mature enough: Among the over 80 SMR concepts analyzed, only a handful are at a noteworthy Technology Readiness Level (TRL) and most of them are in an early stage of development and not in a licensing preparedness process. On the other hand, new concepts are continuously being introduced and some of these concepts could develop and be at a demonstration stage (prototype or licensing) before several of those listed. This selection is limited to those that are at a high readiness level for being commissioned.
7. Less than 5 years of continuous operation: There are several prerequisites that must be met to introduce nuclear reactors on a ship, and one of these are the 5-years intervals where ships are brought to a dry dock for inspection and maintenance according to classification society rules. This means a minimum of 5-years continuous operation before maintenance and ideally that the interval for refueling of reactors should be at least 5 years. However, some reactors have continuous or short period refueling which means that they are refueled onboard, such as some molten salt reactors.
8. Using classic pebble bed technology: In a challenging marine environment, there are certain limitations on structures that cannot withstand sudden movements or disturbances of ocean waves. That could be the case for High Temperature Gas Reactors (HTGR) based on pebble bed technology, and the main reason why it was excluded from the list.
9. Too high pressure in the reactor primary system: Similarly, it is also important to limit the pressure allowed in the reactor vessel, so that it is guaranteed that the pressure limit in accidental conditions is below the limit of what the ship structures can sustain. Reactor concepts that cannot guarantee this, are excluded.
10. Violent reaction of coolant with water: In a marine environment, the chemical reactivity of coolants and salts is an issue. This excludes molten salt reactors based on highly soluble compounds such as NaCl due to the violent reaction of high temperature molten salt interacting with water. Based on the same criteria, Sodium-cooled Fast Reactors (SFR) technology is excluded.
11. Violation of export control: Export control issues (and trade embargos) with some countries must also be considered. These embargos could be important for purchasing materials such as graphite used as moderator in several reactor concepts.

3.2 The three main types of reactors

Based on the discussion of exclusion criteria, only three categories of reactors were considered for marine applications in this study and will be briefly described in this chapter. Only seven reactor concepts survived the exclusion process. However, we are not referring to any vendors in the discussion.

3.2.1 Molten Salt Reactors (MSR)

In a molten salt reactor, the primary coolant and/or the fuel is a mixture of molten salt with a fissionable material. An MSR could also be a combination of Tri-structural Isotropic (TRISO) particle fuel in pebble form coupled with molten fluoride salt as coolant. There are several reactor concepts of MSRs [15], and it would be beyond the scope of this paper to describe the different concepts in detail. Altogether 13 reactor concepts were reviewed, and only a few of these reactor concepts survived the evaluation by exclusion criteria.

One of the main advantages of MSRs for marine applications is that it can operate at or very close to atmospheric pressure and can be refueled while in operation. However, this can also face problems related to proliferation and crossing different jurisdictions. Another advantage is the retention of fissile material in the salt, or intrinsic retention in TRISO fuel, and complete unit decommissioning. Depending on the reactor concept, refueling could take place onboard continuously (online refueling or during certain periods (months/years)), or in other cases during the 5-year maintenance intervals of ships. Note that the refueling operations in the MSRs considered involve only the addition of small amounts of fresh makeup fuel salt to maintain power and no extraction of spent fuel salt is performed, which would pose serious challenges from the proliferation point of view. MSRs are expected to need extensive qualification of materials to address possible corrosion issues.

3.2.2. High Temperature Gas-Cooled Reactors (HTGR)

The reactor being investigated for marine applications has TRISO fuel in a prismatic array and is cooled by Helium. The thermal power is in the lower range of SMRs which makes them suitable for smaller ships, unless it is placed in an array of 2-3 units. The main advantages of helium-cooled reactors are that helium is an inert gas, the intrinsic retention of fission products in TRISO particles and its high proliferation resistance despite high fuel enrichment (between 9.99% and 19.75%). However, the reactor uses a pressurized vessel, which could be a disadvantage. Another advantage for marine applications is that the reactor has no moving parts and can be placed horizontally, thus limiting the space occupied. Furthermore, helium is a benign gas regarding corrosion.

3.2.3. Lead-Cooled Fast Reactors (LFR)

Lead-cooled reactors are a type of nuclear reactor that uses liquid lead or lead-bismuth eutectic as the primary coolant. This type of reactors has several advantages such as high operating efficiency at atmospheric pressure, inherent safety, no need for any refueling, and closed unit decommissioning. The main drawback is the production of polonium, which, in the event of coolant leakage, Po-210 constitutes a radiological hazard, requiring methods based on alkaline extraction to safeguard both personnel and the environment. Lead is considered a more attractive coolant option than lead-bismuth, mainly due to its higher availability, lower price, and lower amount of induced polonium activity (by a factor of 10^4 compared with lead-bismuth), which is why lead-bismuth reactors are excluded.

The pure liquid-lead cooled reactors have potential problems of clogging during operation and will need external heating while reducing/increasing the power. However, the use of lead as a coolant has advantages as it is a radiation shielding and makes it possible to achieve passive safety systems. Liquid-lead reactors are also known to have corrosion issues.

3.3 The criteria for the final selection of reactors for marine propulsion

Following the discussion of 11 exclusion criteria, the 26 selection criteria and sub-criteria are reviewed that were identified through a series of workshops and discussions of the NuProShip I project throughout 2023. Many of the participants in the NuProShip I project have extensive experience in both ship design and shipbuilding, offering insights when useful. In Figure 3, the set of evaluation criteria and sub-criteria are hierarchically displayed as mandated by AHP. Starting from the left to the right, the following criteria and sub-criteria are proposed:

1. Reactor Core Characteristics: The core of the reactor will determine its behavior, and it is therefore an important criterion to consider:
   a. Fuel Safety: Behavior of the fuel in an accident and its environmental impact is a key factor. Different reactor concepts make use of nuclear fuel in different forms with a different degree of safety. For example, TRISO fuel is considered the most robust nuclear fuel ever engineered [6] given its capability to retain fission products and to withstand extreme temperatures. In contrast, conventional oxide pellets organized in fuel assemblies have shown potential safety issues, such as swelling, cracking, mechanical interaction with cladding, that could lead to fission product release, when operating at abnormal temperatures [11].
   b. Coolant Toxicity: Harmful effect of the coolant is important. While the safety shall be excellent, there can always be a small possibility of coolant leakage or spillage during maintenance operations, and to minimize the toxicity of the coolant is therefore important for workers and the environment.
   c. Source Term: The types and amounts of radioactive- or hazardous substances that could be released to the environment following an accident – reflecting the potential radiological consequences – are also important safety parameters. Different reactor concepts may have different source terms, depending on the fuel type, coolant type, operating conditions, etc.

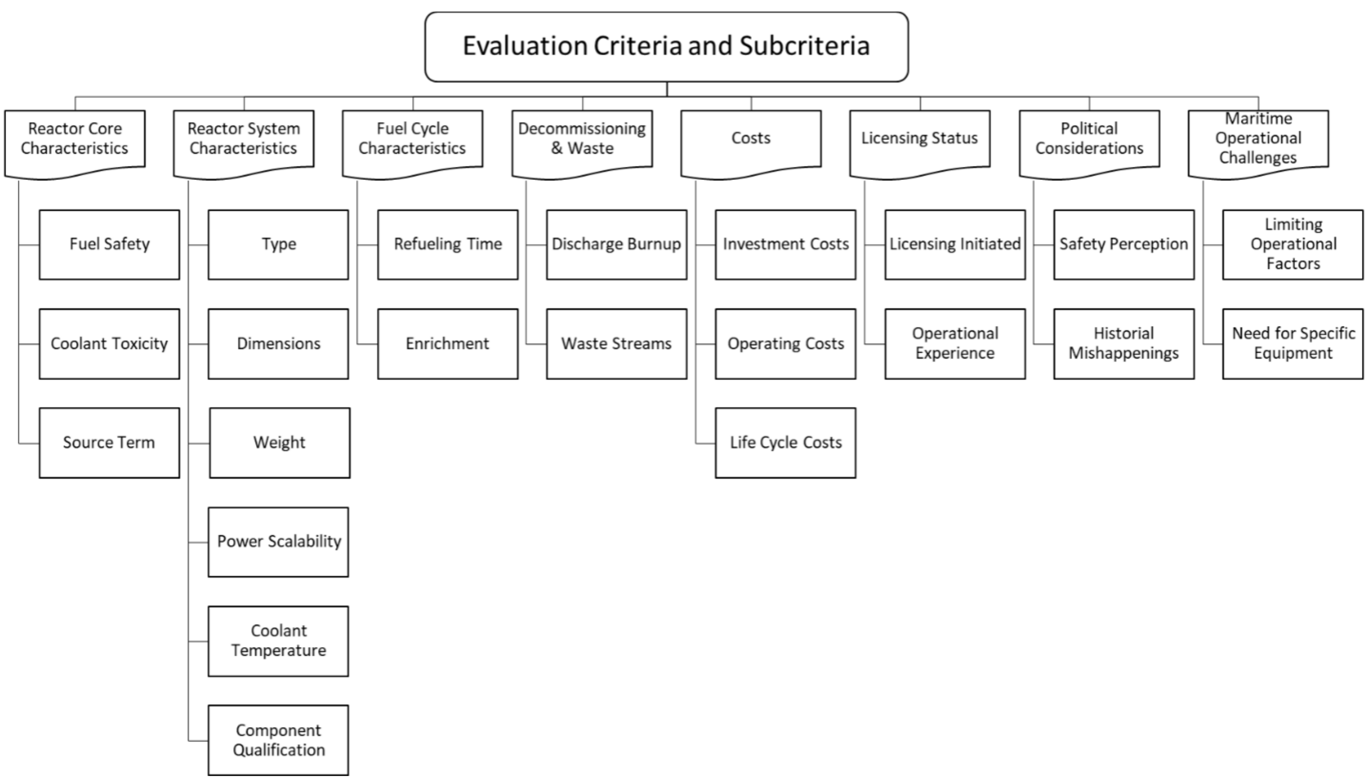

FIGURE 3 – THE CRITERIA FOR SELECTING NUCLEAR REACTOR CONCEPTS FOR PROPULSION OF MERCHANT SHIPS.

2. Reactor System Characteristics: This criterion is important as it is key for the interaction with the ship, and it is refined into 6 sub-criteria:
   a. Type: whether the secondary system consists of one or more loops (with natural or forced convection) or the design is integral, with the secondary system held inside the reactor vessel, will have consequences for the overall system complexity and performance.
   b. Dimensions: Size of the propulsion unit, which is a criterion that relates to the fact that space is expensive on ships unlike land.
   c. Weight: Weight of the propulsion unit is another physical aspect that must be taken into account.
   d. Power Scalability: Considers the different ways the propulsion unit can increase/decrease its power, whether by adding more reactor units, by increasing/decreasing the enrichment or size, etc. This criterion basically concerns the fact that ships come in all shapes and sizes with different requirements.
   e. Coolant Temperature: Outlet temperature of the reactor coolant is an important criterion since it will impact many ship systems concerning how to handle the cooling.
   f. Component Qualification: New components and materials often lead to time-consuming qualification processes to be avoided.
3. Fuel Cycle Characteristics: There are particularly two aspects of the fuel cycle that are considered important:
   a. Refueling Time: Reactors will at some point need to be refueled and ideally, that should take place when the ship docks for inspection by the classification society to ensure safety standards are upheld. This docking takes place every 5 years. The expected life of the ship is 30 years, so every 5, 10 or 15 years would be ideal. Nevertheless, reactors without refueling are considered advantageous.
   b. Enrichment: This factor considers the increased percentage of U-235 needed for the operation of the reactor. Enrichment is primarily a cost issue as well as a potentially political issue.
4. Decommissioning and Waste: Both decommissioning and waste are important criteria because they can be potential showstoppers if the costs become prohibitively large. This criterion is broken down into two:
   a. Discharge Burnup: burnup of the spent nuclear fuel. It is a measure of how much energy has been extracted from the nuclear fuel.
   b. Waste Streams: estimated types and amounts of radioactive waste generated in operation.
5. Costs: The criteria related to costs are omitted in the initial selection because the information is not mature enough to provide reasonable accurate cost estimates. Furthermore, the cost estimates provided by the vendors themselves vary too much to be consistent. The cost criteria will therefore be reviewed at a later stage once more mature information is available to primarily ensure that we avoid double counting as well as correct estimates of individual costs.
   a. Investment Costs: The costs of the fabrication, construction, commissioning and licensing of the propulsion unit is an important economic criterion because there is a strong focus on investment costs in the shipping industry. Note that the propulsion unit includes the reactor as well as any auxiliary systems such as heat exchangers, turbines and load management system needed for its safe operation to propel ships.
   b. Operating Costs: Costs of the operation of the propulsion unit. Operational costs are also key because in the shipping industry as the margins can be tight at times.
   c. Life Cycle Costs: Costs of the decommissioning of the propulsion unit as well as waste handling will ultimately impact the total economics of the reactor concept, which will impact the Levelized Cost of Energy metric often used to compare technologies and policymaking worldwide [17].
6. Licensing Status: The purpose of this criterion is to avoid selecting reactor concepts that are basically too difficult in terms of approval or too far into the future:
   a. Licensing Initiated: Whether the licensing process of the reactor has been started at any country is evaluated as a great start, although it is a reality that the road may still be long and winding before a license is obtained.
   b. Operational Experience: Describes whether the technology of the nuclear reactor is completely new or already exists some operational experience.
7. Political Considerations: Politics has always been a part of nuclear power, and when a large number of ships are to cross the world's oceans at will, there will be many political issues that reactor concepts will encounter:
   a. Safety Perception: Public and political awareness and understanding of potential hazards and risks of the specific reactor concept, which is a main factor for the public acceptance of nuclear reactors for shipping.
   b. Historical incidents and accidents: Events that occurred in the past, related to the technology with negative or unintended consequences, could jeopardize the deployment of that technology in a reactor concept for shipping.
8. Maritime Operational Challenges: Ships undergo various operational modes through their life cycle, so choosing a reactor that can satisfy these modes is crucial:
   a. Limiting Operational Factors: These aspects are those that can limit, or even make difficult, the applications towards nuclear propulsion. Examples of these challenges are, the effect of the sea movement on reactors relying on natural circulation, the potential clogging problems on Lead-Cooled Reactors due to load variations, etc.
   b. Need for Specific Equipment: This factor essentially focuses on need for the development or implementation of specific equipment needed for the optimal

performance of the nuclear reactor that would be influenced by the maritime environment.

While the final weights for the selection criteria will be determined in Stage 2 through pair-wise comparison in the AHP, it is evident that some of the criteria presented above will most likely carry more importance than others, and consequently will have more impact on the final selection. For instance, criteria like *5. Costs*, *7. Political Considerations* and *8. Maritime Operational Challenges* hold substantial importance due to their direct relevance to economic, political, and technical feasibility. Safety-related considerations such as *1. Reactor Core Characteristics* will obviously play a crucial role. On the other hand, criteria such as *2. Reactor System Characteristics* and *4. Decommissioning and Waste* have comparatively less direct influence as differences in these criteria will probably affect the outcome only slightly.

A key insight we have gained so far is that a one-size-fits-all-approach will fail. The diversity of ship designs and operational modes when mapped onto the characteristics of the reactor concepts and performance profiles, makes it apparent that different reactor concepts will fit with different ship designs and operational modes.

The LNG tanker in Figure 1, for example is crossing the world's oceans from one LNG terminal to another terminal at relatively high speed. The operational profile is therefore fundamentally different from a large cable layer, which is operating at sea by moving slowly forward and using power to stay on a certain GPS position (in more than 6 meters significant wave height) as well as operating large power consumers such as cabling equipment, cranes, subsea equipment and more, see Figure 4.

FIGURE 4 – THE ZEROCLASS CABLE LAYER DEVELOPED BY VARD. SOURCE: VARD.

The LNG tanker will need a reactor that has an effective output at high load which can be ramped down to some extent in the terminals. The cable layer, however, will need a reactor that is good at ramping primarily. Both of them will need a thermal load management system, of course, but the difference in operational profile despite having the similar total power requirements will likely lead to a different preference for reactor concepts.

4.0 FUTURE WORK

The next stage in the process, which is ongoing, is to involve the various vendors of the selected reactor concepts to discuss their technology in more details (without violating export control regulations). This process is key to verify that the publicly available information is still valid. If it is not valid due to design changes, updated information will be requested. These discussions may lead to the introduction of more selection criteria for Stage 2. Once the initial information gathering is performed, the AHP can be executed, and a smaller set of reactor concepts can be chosen. This work is expected to be completed by yearend 2024.

Cost information may take longer to gather and estimate relatively reliably, and estimating the costs after industrialization are even more difficult to estimate. However, they are likely to be significantly lower than the first prototypes.

These reactor concepts will then become mapped onto various ship designs and operational modes to identify which reactor concepts will fit which ship type the best. This work will be performed in the next project, NuProShip II.

5.0 CONCLUSIONS

The paper started out by showing that the DSF pose a significant challenge concerning decarbonization. The case for researching whether or not there are suitable SMRs for DSF is therefore strong. However, given the number of possible reactor concepts, such research must start by first identifying what criteria are useful in selecting SMRs for DSF, which is the purpose of this paper. We have chosen to apply Generation IV requirements as a basic philosophy to achieve political acceptance in numerous flag states which we believe can become an impetus towards further harmonization of licensing rules among countries to enable nuclear merchant shipping and more.

With this background, we have developed a set of exclusion criteria as well as selection criteria that should enable a robust identification of useful reactor concepts. All in all, there are 37 of them – 11 exclusion criteria and 26 selection criteria – covering the entire range of nuclear engineering through politics.

The quality of these criteria will ultimately be determined by the quality of the reactor concept they lead to. However, this remains to be seen as such selection processes are also influenced by information availability where cost information is currently the main challenge.

6.0 ACKNOWLEDGEMENTS

We gratefully acknowledge the financial support from the Research Council of Norway, grant number 336539, as well as the input provided by the other participants in the project team including Eirik Ovrum at Det Norske Veritas (DNV), Bjarne Pareliussen at NTNU Ålesund, Luís Filipe Baptista at Escola Náutica Infante D. Henrique (ENIDH), Håvard Lien at Vard Group AS and Even Bjørnevik from Knutsen OAS as well as a many other shipping industry professionals that have provided input at various occasions.

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Energy Research & Social Science 119 (2025) 103897

Contents lists available at ScienceDirect

Energy Research & Social Science

journal homepage: www.elsevier.com/locate/erss

Review

Rethinking the "Levelized Cost of Energy": A critical review and evaluation of the concept

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ARTICLE INFO

Keywords
Capacity
Discounting rate
Lifespan
Marginal costs
Reliability
System effectiveness

ABSTRACT

The Levelized Cost of Energy (LCOE) is frequently used for policymaking worldwide, modeling and in assessing the cost competitiveness of technologies, but its formulation is deceptively simple. The result is that many caveats are obscured, but they are important to understand so that LCOE calculations can become more accurate and communicated more correctly to avoid misleading policymakers and decisionmakers. The paper discusses the approach, and how a handful of influential and reputable organizations calculate and communicate the LCOE. The conclusion is that the introduction of variable renewable energy sources into the grid has made the LCOE questionable towards it initial purpose of providing a sound basis for comparison, and most reputed organizations fail to address the issues both computationally and in their communication. However, significant improvements to regain relevance can be made by using realistic assumptions as shown by presenting a reconceptualized version of LCOE and communicate the unsolved shortcomings to stakeholders.

1. Introduction

Calculating the costs of energy sources are important for a variety of reasons. For example, cost estimates are used when the Intergovernmental Panel on Climate Change (IPCC) are designing their scenarios: "The actual representation of technological change in the six SRES [Special Report on Emissions Scenarios] models range from exogenously prescribed availability, through cost and performance profiles (which in some cases also include consumer or end-use costs for technology use), to stylized representation of learning processes" [1]. Furthermore, they note that population and gross domestic product assumptions, along with structural change and technological change that affect energy efficiency and energy costs (and prices), drive the demand for energy services. "Therefore, most models treat dynamic changes in (average and marginal) costs as the driving force for energy intensity improvements and for technology choice".

When it comes to the cost estimates themselves, the IPCC relies on 'levelized cost' of various kinds such as Levelized Cost of Energy (LCOE), Levelized Cost of Conserved Energy (LCCE), Levelized Cost of Conserved Carbon (LCCC) to facilitate a meaningful comparison of economics across diverse options at the technology level [2]. This paper focuses on LCOE since it is frequently used for policymaking worldwide [3], modeling, public discussion, and estimating cost competitiveness for power generation technologies [4], and to establish price-based support instruments such as premiums, feed-in tariffs, Contracts for Difference (CfD) and green certificates [5].

Unfortunately, misleading LCOE estimates have become the norm as shown later. In fact, Schernikau et al. [6] interviewed 70 experts, and found that "the overarching theme was the lack of understanding of the true, full cost of electricity and continued misuse of the marginal cost measure LCOE to compare costs of Variable Renewable Energy (VRE) with conventional sources of power". The authors suggest stop using LCOE altogether.

Note that to describe the LCOE as a 'marginal cost measure' is unusual, but its origin is related to dispatchable fossil energy sources for which the cost of an additional unit of energy would be quite close to the LCOE since the capital component was relatively lower and decommissioning and waste costs was far into the future with small impact on the discounted values. This is, however, no longer true. The IEA [4] sums up the situation like;

In the regulated markets of the past, the technology with the lowest LCOE really was indeed also the best baseload investment choice. This no longer holds true. First, structural changes in demand and supply, in particular the advent of significant shares of variable renewables with zero short-run marginal costs… []…Second, the complexity of markets with a spectrum of flexibility needs leads to increased "revenue stacking" even for former baseload producers rather than dedicated production for one single (forward) market. Third, in the context of these increased flexibility needs, portfolio

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https://doi.org/10.1016/j.erss.2024.103897
Received 12 May 2024; Received in revised form 23 October 2024; Accepted 13 December 2024
Available online 23 December 2024

effects become increasingly important rather than the technical characteristics of individual units. Fourth, and most importantly, in systems with large shares of variable renewables, one must complement cost considerations with value considerations, or, equivalently, account for costs at the system rather than at the plant level.

Clearly, some issues concerning the LCOE are recognized, but the calculations of the LCOE are not amended. In fact, in many contexts its communication is outright misleading. For example, when IRENA [7] claim that "the global weighted average LCOE of utility-scale PV plants is estimated to have fallen by 77% between 2010 and 2018, from around USD 0.37/kWh to USD 0.085/kWh, while auction and tender results suggest they will fall to between USD 0.08/kWh and 0.02/kWh in 2030" they are using LCOE in a narrow sense where the asset is the system boundary, denoted 'Asset LCOE' in the remainder of this paper. The statement is probably true on asset level, but it ignores the additional cost of integrating VREs into the grid, unless they accept that power will follow the weather, and the economic- and environmental externalities. Literally all the reputed organizations make such statements. It is notable that the power prices increased so much when the LCOE has been falling. The reason is that the system costs have grown substantially and to the extent that it can no longer be ignored when comparing energy sources. Moreover, as early as 2013, the IEA sounded a warning on Energiewende (the German energy transition), and IEA Executive Director Maria van der Hoeven said that "The fact that German electricity prices are among the highest in Europe, despite relatively low wholesale prices, must serve as a warning signal," as she presented the report [8]. Hence, performance validity, see Section 2.0, is weak.

The described situation is well known among knowledgeable researchers and practitioners, but it is hardly desirable or acceptable. Hence, the purpose of this paper is to critically review how LCOE is being calculated and communicated, what the shortcomings are and how they can be resolved. To do that we must start with its origin. Historically, the LCOE concept was developed in order to help choose between different dispatchable baseload technologies in regulated systems [4].

These issues ultimately lead to the research question 'how can LCOE calculation be improved to provide a basis for comparison for all types of energy sources?' This research question is too large to address in a single paper, so the purpose of this initial paper is to merely identify the shortcomings of its calculations, how it is communication by reputed organizations and propose significant improvements without undue complexity being added. Hence, this author believes it is better to reconceptualize the LOCE, and communicate clearly residual caveats to decisionmakers, than to discontinue its usage as suggested by Schernikau et al. [6] and others.

Section 2 describes the research method. In Section 3, the LCOE is presented along with some basic physical properties of power systems to provide background for Section 4 where the contentious issues are discussed in details. Sections 3 and 4 provide the necessary insights to present a rethought LCOE concept in Section 5. Then, in Section 6 we discuss how some reputable organizations calculate the LCOE. Section 7 contains some critical thoughts on the presented work followed by conclusions in Section 8.

2. Methods

In the field of energy research, there are seven key themes concerning methodology and method [9]: 1) problems of knowledge production; 2) researching norms and ideologies; 3) grappling with interdisciplinarity and multiple methods; 4) exploring energy culture and behavior; 5) comparative and multilevel studies; 6) temporal and longitudinal studies; and 7) participatory and action research. The authors find that'Fruitful analysis may be forced to become what is known as 'transdisciplinary', 'interdisciplinary' or 'multi-method'. This is also the case in this paper.

Since the purpose of LCC, and by logical extension LCOE, is to help 'engineers think like MBAs' [10], striking the right balance between engineering and finance is important. The paper therefore contains an engineering section (Section 3) followed by a financial section (Section 4).

Most papers on LCOE this author have read, are either short or entirely missing engineering related discussions. They just plug the numbers into the LCOE formula. Unfortunately, this is no anomaly. An examination of 15 years of peer-reviewed publications in energy social science found that 29 % of the 4444 studies examined had no description of an explicit research design—or method—whatsoever [11].

As thoroughly demonstrated by Sovacool et al. [12], addressing research in energy social sciences can be done in many different ways. Regardless of its context, the authors emphasize 'rigor', which the simple Oxford definition states as "the quality of being extremely thorough and careful." This paper will therefore attempt to provide both an engineering discussion and a financial discussion that are logically consistent both within their respective disciplines and between the disciplines. This is challenging, but regardless of which part of the elephant we study, the parts cannot contradict each other.

The challenge of a critical review like this one is that so many different researchers, practitioners, policymakers and so on use the LCOE measure. A simple Google search 2024-05-01 on 'Levelized Cost of Energy' provides 5.85 million hits, and in Google Scholar we obtain 46,000 hits. Reviewing all these documents formally, even if we limit ourselves to purely academic publications, is a major project in itself.

However, a few, reputable organizations have a disproportionate impact on the LOCE usage as they are frequently cited. Therefore, a critical review of these few is far more interesting than a typical literature review of the many. Also, these organizations have enough publications to identify the details regarding how the actually use the LCOE, which provides greater validity. As such, the method employed here is closest to the integrative literature review, see [13], but this paper does not offer a large enough sample to constitute a formal literature review per definition. The evaluation is based on identifying how they handle the contentious issues discussed in Section 3 and 4, and how well the method of a reputable organization corresponds to the reconceptualized LCOE approach presented in Section 5.

The next issue is the selection of reputable organizations. Initially, the key UN organizations were chosen, EU and the US. Then, also a few industry organizations were added. It turned out that there are relatively small differences in the usage of the LCOE. Thus, adding more organizations would make little sense, and the final selection of eight organizations is found in Section 6.

Due to the fact that energy policy has become an increasingly contentious issue, we run the risk of 'maintaining objectivity while communicating science on a controversial topic can sometimes prompt one to adopt less critical perspectives' [14], which can be inferred from the fact that scientific knowledge and 'truth' are socially justifiable beliefs, according to Hegel and later articulated by Dewey [15].

This does not necessarily compromise scientific rigor per se. Even the so called 'exact sciences' are dominated by approximations [16]. Indeed, Kurt Gödel, the greatest mathematical logician ever [17], proved mathematically by his 'Incompleteness Theorem' that "every formal number theory contains an undecidable formula, i.e., neither the formula nor its negation is provable in the theory" [18,19]. Indeed, logic (such as formal systems) is consistent *within* itself but 'content free' [20], and Einstein [21] compared the scientific method to a game – it is the fixation of the rules that count. The same holds for purely empirical work. Quine [22] argued strongly that 'we choose a particular way of doing it [accommodate a theory to an experiment] not because some absolute scientific principle but because it is convenient, causing minimal disturbance in the existing theory'.

Fortunately, there are methods designed for developing- and evaluating methods to maintain scientific rigor; the Validation square of [23]. Note that in the modeling literature, verification refers to internal consistency, whereas validation refers to justification of knowledge claims which is the opposite of the definitions used in some other parts of the literature [24]. The conclusion of the methods research became [25]: A scientifically valid method must be both structural-valid and performance-valid, where structural validity has three complementary facets: 1) the internal consistency of each of the individual constructs constituting the method; 2) the internal consistency of the method itself, as an integration of parent constructs, and 3) the appropriateness of the example problems used to verify the performance of the method. Furthermore, performance validation has three complementary facets: I) establishing that the outcome of the method is useful with respect to its intended purpose for the chosen example problem(s), II) establishing that the demonstrated usefulness is linked to applying the method itself; and III) reasoning that the method is useful for domains that are broader than the chosen examples. These terms will be used throughout the paper where relevant to validate the research and point towards future work.

3. The LCOE and engineering realities

When we discuss the LCOE approach, there are four aspects that are important to keep an eye on. First, we have the formula and the parameters included in it, as discussed in Section 3.1. Second, we must secure comparability, as discussed in Section 3.2. Then, the underlying assumption of system stability and how it influences the LCOE is discussed in Section 3.3. Fourth, the dispatch priority and its influence on capacity utilization as discussed in Section 3.4. The latter two do not directly impact the calculation itself when applying the LCOE formula at asset level (Asset LCOE), but they nonetheless have major impact on the true total costs.

3.1. LCOE today

The standard formula used for calculating the Asset LCOE is [3]:

$$\mathrm{LCOE} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \tag{1}$$

Where:

LCOE = the average lifetime levelized cost of energy generation.

I_t = investment expenditures in the year t.

M_t = operations and maintenance expenditures in the year t.

F_t = fuel expenditures in the year t.

E_t = electricity generation in the year t.

r = real discount rate, i.e., the nominal discount rate adjusted for inflation.

n = economic life of the system.

Hence, the LCOE is the discounted life-cycle cost per energy unit for a given energy technology over its entire life-cycle, cradle to grave. Thus, LCOE is a subset of LCC. However, this formula is deceptively simple where keeping an eye on the assumptions are crucial but rarely reported or even understood [26]. Yet, the IEA [4] describes the LCOE in the foreword as a "…uniquely transparent and intuitive metric,…".

But the confusion arises in parts of the literature because, "The calculation of the LCOE is based on the equivalence of the present value of the sum of discounted revenues and the present value of the sum of discounted costs", and "It is not the MWhs that are being discounted; it is the revenue from those MWh that is being discounted" [4]. Therefore, this equivalence suggests that LCOE is essentially the average, constant price throughout the life-cycle of the asset that would balance its life-cycle costs (P_E in Eq. 2 below). Put differently [4], but improved by the author to reflect mathematical rules more completely;

$$\sum_{t=1}^{n}\left(P_E \times E_t \times (1+r)^{-t}\right) = \sum_{t=1}^{n}\left(Capital_t + O\&M_t + Fuel_t + Carbon_t + D\&W_t\right) \times (1+r)^{-t} \tag{2}$$

Where:

P_E = The constant lifetime remuneration to the supplier for electricity [USD/MWh].

E_t = The amount of electricity produced annually in year t [MWh].

r = The real discount rate corresponding to the cost of capital.

$Capital_t$ = Total capital construction costs in year t [USD].

$O\&M_t$ = Operation and maintenance costs in year t [USD].

$Fuel_t$ = Fuel costs in year t [USD].

$Carbon_t$ = Carbon costs in year t [USD].

$D\&W_t$ = Decommissioning and waste management costs in year t [USD].

Rearranging Eq. (2) yields Eq. (1) given that LCOE = P_E, but Eq. (2) was only true in a regulated market where a public utility was expected to go break even (costs balancing revenues) with modest profits if any. Krey et al. [2] state that leveling costs means to express all lifetime expenditures of a stream of relatively homogeneous outputs that occur over time as cost per unit of output. LCOE is "the cost per unit of energy that, if held constant through the analysis period, would provide the same net present revenue value as the net present value cost of the system" [27]. Put differently, the LCOE defined above is the long-term offtake price needed to achieve a required equity hurdle rate for a new power generation project, and for a project developer it is the wholesale power price needed at commissioning to cover all project costs, excluding grid connection costs, to achieve a given equity return rate in the absence of subsidies [28].

Thus, the definition ignores the system part because no integration costs are included, or it was assumed that system costs would be evenly distributed among all generators if correct cost assignment had taken place. This made sense for dispatchable energy sources in a regulated market and the focus could be on the asset itself to simplify the calculations. The assumptions underlying these statements no longer hold true in a deregulated, profit maximizing market. Otherwise, no profits can be made since the equations balance out without profits.

Deregulation has, however, also real economic effects that renders direct comparison misleading before and after. For example, from 1990 to 1996 in the US, the thermal efficiency grew by 0.2 % per year, staff was reduced by 7 % and refueling time cut by a third and the number of nuclear power plants that managed a Power Capacity Factor (PCF) above 70 % almost doubled [29].

Deregulation has also changed the revenue driver for assets. When, the market was regulated the key was to maintain high reliability since prices were regulated [30]. With a deregulated market and the introduction of VREs, however, this situation has changed. Now, it is the prices that determines the outcome to a much higher degree.

Using the Validation Square, we understand that the internal consistency is suffering due to changing context. The LCOE should therefore be reconceptualized. Hence, we must offer a modernized reconceptualization of the LCOE that fits the current market and technology.

3.2. LCOE and comparability

A key issues is that the intermittency, non-dispatchable feature, and variable output of VREs makes their integration currently unsatisfactory [31]. For VREs where the output varies by the minute, this averaging of the costs as suggested by the traditional usage of the LCOE formula, becomes fundamentally wrong because it ignores the opportunity costs that can be significant [32].

Note that in economics, opportunity cost has two related interpretations [33]: It can be "the alternative that must be foregone when something is produced" or "the amount that an input could earn in its best alternative use". It is therefore different from accounting costs that are explicit whereas opportunity costs include explicit as well as implicit costs that are foregone. Hence, value is a key aspect of opportunity cost [34], but value is more than the narrowly defined value discussed in Section 4.3.

Also note that the proper measurement of integration costs is a hotly

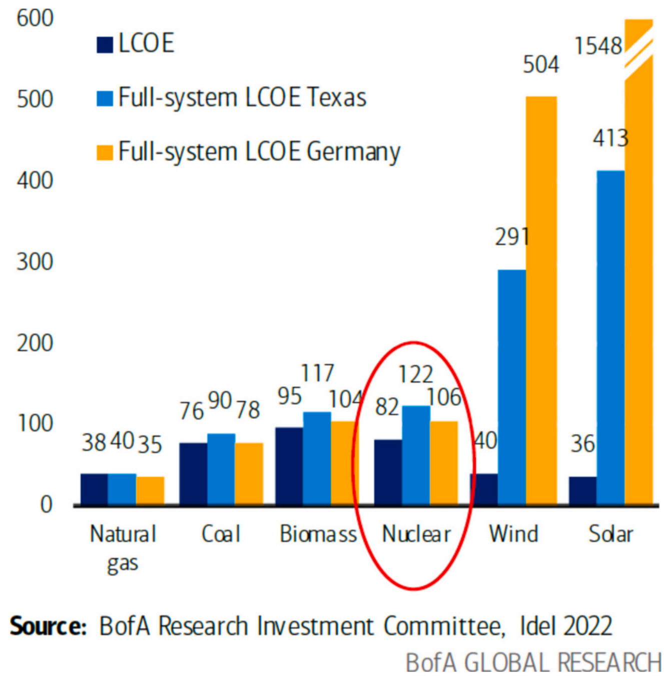

Fig. 1. LCOE & LFSCOE calculations by energy technology. Source: [53].

debated subject in academic as well as policymaking circles, and a generally accepted definition of "integration costs" does not exist and calculations are subject to large uncertainties and controversies, including predictions about future development of power systems [35]. There is a range of terms used today including "hidden cost" [36], "balancing cost" [37], "system level cost" [38], "variability cost" [39], and also the term "integration cost" is widely adopted but the definitions vary [40]. Irrespectively of terms, these costs are commonly socialized in the power system [40].

One of the people to discuss these topics early is Joskow [41], and since then a number of refinements have been proposed such as including price variations [42], use reference scenarios and provide a comparative LCOE analysis [43], explicitly model the uncertainty [44,45], include Power Purchase Agreements (PPA) [46] and we can take an investor's view and assume investment positions and various ownership stakes through different phases of the life cycle of a wind power plant [44].

Indeed, by using audited information from Special Purpose Vehicle companies – which many wind power plants are defined to manage risks – Aldersey-Williams et al. [47] find an accurate way to calculate the LCOE for given years, on asset level. The results reveal that open domain data are unreliable. For example, they found that new wind power plants were achieving a LCOE of around 100 GBP/MWh which was considerably higher than implied by the CfD bids of 57.50 GBP/MWh at the time. The problem is that these LCOE calculations are retrospective.

Unfortunately, none of these refinements sufficiently address system costs. There are a few ways of overcoming this shortcoming. First, the LCOE can be augmented into a 'System LCOE', as suggested by [48,49]. However, without an explication of the system effectiveness we may have improved the integration cost issues but not addressed the opportunity costs.

An interesting approach is to actually include other revenues than those related to selling the energy as suggested by de-Simón-Martín et al. [50]. The 'other revenues' are the possible yearly benefits that may reduce the costs including incentives, internalities intended as indirect benefits, avoided externalities, as well as other indirect benefits for a third party. These 'other revenues' are essential some of the costs society is carrying on behalf of the asset in question. The same approach can also handle uncertainty [51]. It is developed for Renewable Energy

Table 1
Resource attributes related to VREs. Source: [54].

Attribute	Renewable Energy Technologies
Capability(a): • Peak capability • Energy capability • Seasonal and hourly profiles	Hydro-, solar-, and, wind options typically have pronounced seasonal profiles. Solar- and wind options also have pronounced hourly profiles.
Availability(a): • Intermittence • Forced outages • Maintenance requirements • Correlation with weather, hydrological conditions and demand	Hydro capability is dependent on hydrological conditions. Plants on the same river system are tightly correlated. Wind and solar are intermittent. Units in the same area are correlated with each other and may be correlated with the weather-sensitive component of system demand.
Efficiency: • Heat rate	Efficiency is generally not an issue for renewables because they typically rely on zero- or low-cost energy sources.
Dispatchability: • Fully dispatchable • Curtailable • Base-loaded • Constraints; ramp rate, minimum output, uptime and downtime.	Run-of-river hydro is non-dispatchable. Pondage hydro is dispatchable. Wind is non-dispatchable. Solar thermal is dispatchable. Other solar options are non-dispatchable. Biomass, landfill methane, and municipal solid waste (MSW) options are typically non-dispatchable. Geothermal is typically non-dispatchable.
Location (c): • Delivery point	Connected at transmission or distribution level. Can be targeted to defer transmission or distribution upgrades.
Modularity(a): • Incremental size • Preconstruction- and construction lead time	Incremental sizes and lead times of renewable energy technologies, except for Municipal Solid Waste (MSW), are typically smaller and shorter than for conventional options. Lead times for MSW are 3 to 4 years.
Costs: • Construction • O&M (Operations and maintenance) • Fuel • Decommissioning costs	Typically, no fuel costs, except biomass. These technologies provide diversification of the fuel supply portfolio. Note correlation with other system costs.
Incentives: • Tax credits (1) • Shareholder incentives (1) • Emission allowance incentives	The 1992 National Energy Policy Act provides a 1.5 cents/kWh tax credit for renewable energy producers. The 1990 Clean Air Act Amendments provide bonus emission credits for renewable energy production.
Risk-Diversity: • Startup delay • Construction cost overrun • Fuel- and O&M costs • Reliability problems • Premature retirement • Diversity	Less mature technologies may have greater construction and operating risks than conventional technologies. Renewable resources generally enhance diversity, except for hydro additions to a predominantly hydro system. Renewable resources generally enhance diversity, except for hydro additions to a predominantly hydro system.
External Costs (2,3): • Air and water emissions • Land use • Waste disposal • Public safety	Land use and fish habitats are significant issues for hydro generation. Noise and visual impacts are issues for wind energy resources.

1) Applicable only to investor-owned utilities.
2) External costs are defined to exclude impacts that are accounted for in other cost categories.
3) Cost-benefit framework must account for avoided externalities from existing generation.

Communities and Sustainable Energy Communities (essentially small grids). While the systems costs are not handled directly since they are socialized to a broader extent than subsidies, it augments the Asset LCOE to probably the most complete Asset LCOE this author has identified.

A simpler approach that addresses the entire grid is offered by Emblemsvåg [52] who essentially model the consequences of geographical diversification in terms of how many wind power plants

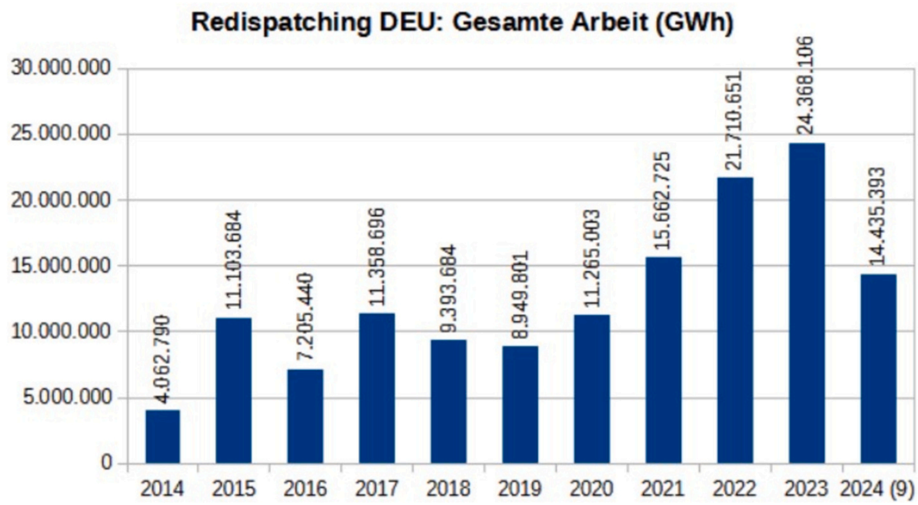

Fig. 2. Consequences of redispatch [GWh]in Germany. Source: The graph is provided by Herbert Saurugg and reproduced with kind permission. His data are from www.netztransparenz.de/de-de/Systemdienstleistungen/Betriebsfuehrung/Redispatch.

are required to guarantee a specific output given perfectly uncorrelated weather systems. Using backup power to fill any production gaps on top, the results show that the System LCOE is roughly 3 times higher than the Asset LCOE at the best case. This is a simpler, top-down approach than the bottom-up approach suggested by Reichenberg et al. 2018 [48] and Ueckerdt et al. [49], and as such more inaccurate. However, it captures a larger part of the opportunity costs because it focuses on the cost of guaranteeing an output as opposed to an upward aggregation where there is no clearly defined system performance requirements associated with the asset under discussion. The same author, also offered a third approach of using Battery Energy Storage Systems (BESS) in combination with Solar Photovoltaics (PV) [32]. Again, the System LCOE became much higher than what the industry uses.

Bank of America has lately performed an analysis of energy technologies where they have added the system costs, and they end up with the results shown in Fig. 1. Compared to the standard LCOE, we see that the Levelized Full System Cost of Energy (LFSCOE) is far larger for VREs. As expected, the LFSCOE will change depending on the system costs. Sadly, the report is short on methods and explanations. However, the report does seriously question the realism of the LCOE estimates used today for policymaking.

Clearly, many LCOE calculations fail to provide a true basis for comparison and thereby fail the performance validity test. The topic discussed in Section 3.3 exacerbates the situation further.

3.3. LCOE and system stability

The stability of the power system is of great importance, and many researchers base their work on (Logan et al. [54], which is the earliest comprehensive source this author has identified for correctly analyzing, in line with LCC principles, the integration of VREs in grids. The resource attributes relevant for VREs presented in Table 1 are worth repeating because in many publications they are partially or totally ignored. RAM is almost always ignored. Note that Table 1 does not include financial issues such as discounting, and some of the content related to tax credits is obviously out of date.

Reliability, Availability and Maintainability (RAM) is a key element in LCC [55] and therefore also for the LCOE. More generically, we talk about system effectiveness, RAM and capability [10]. For dispatchable energy sources, many of the LCOE caveats are not major issues since production is either steady or adjustable to demand so that the system effectiveness is largely controllable unless there are unplanned downtime.

A weakness with RAM is that it is often hardware-focused [56], but it is suitable for the purpose of grid operations. Indeed, there are multiple models to choose from since the concept has been developed since the 50s and 60s, see [56]. The RAM term itself can be defined as [57]; Reliability is concerned with the probability of the system of interest working when it should. The term Availability in itself is imprecise as it may, or may not include logistics and administrative delay time, corrective and preventive maintenance. Therefore, we categorize Availability into Inherent, Achieved, or Operational Availability. Finally, Maintainability is concerned with keeping the system working and the ease of putting things right once they have gone wrong.

The point is that the RAM requirements of a system are major drivers in the need for support resources and the related in-service costs [58]. This has been well-known in traditional systems engineering applications such as advanced weapon systems, but it certainly also concerns grids. In their study after the blackout in Turkey in 2015, Project Group Turkey [59] argues that “A large electric power system is the most complex existing man-made machine”. Hence, RAM is key, and we must also think of the system reserves to maintain reliable service. Otherwise, we are shorting the grid, as Angwin [30] eloquently describes it.

The grid is to provide electricity 24/7 without any noticeable downtime. In real life, the system reliability is measured by the LOLP and LOLE [60] and they are used as dimensional parameters for the system reserve. LOLP refers to the probability of a loss of load event in which the system load is greater than available generating capacity during a given time period. LOLP is typically computed in one-hour increments, whereas the LOLE is the sum of the LOLPs during a planning period – typically one year. LOLE gives the expected number of time periods in which a loss of load event occurs [61]. Power system planners typically aim at maintaining a LOLE value of 0.1 days/year, or 2.4 hours per year based on the target of one outage-day every 10 years [62]. Due to iterative calculations, the approach is relatively computationally heavy [61].

Managing the grid has become much more difficult over the last decade. In Fig. 2 we see the development of redispatch, i.e., the replanning of the use of power plants in the event of power grid fluctuations, over the last decade including 9 months of 2024. The introduction VREs has had major consequences which are today socialized and converted to system costs. The number of incidents has the same overall trend. In 2023 the number of incidents in Germany was 15.192, or more than 40 per day on average. According to Herbert Saurugg, 20 years ago the number was single digits per year[1].

[1] Personal communication 2024-10-08

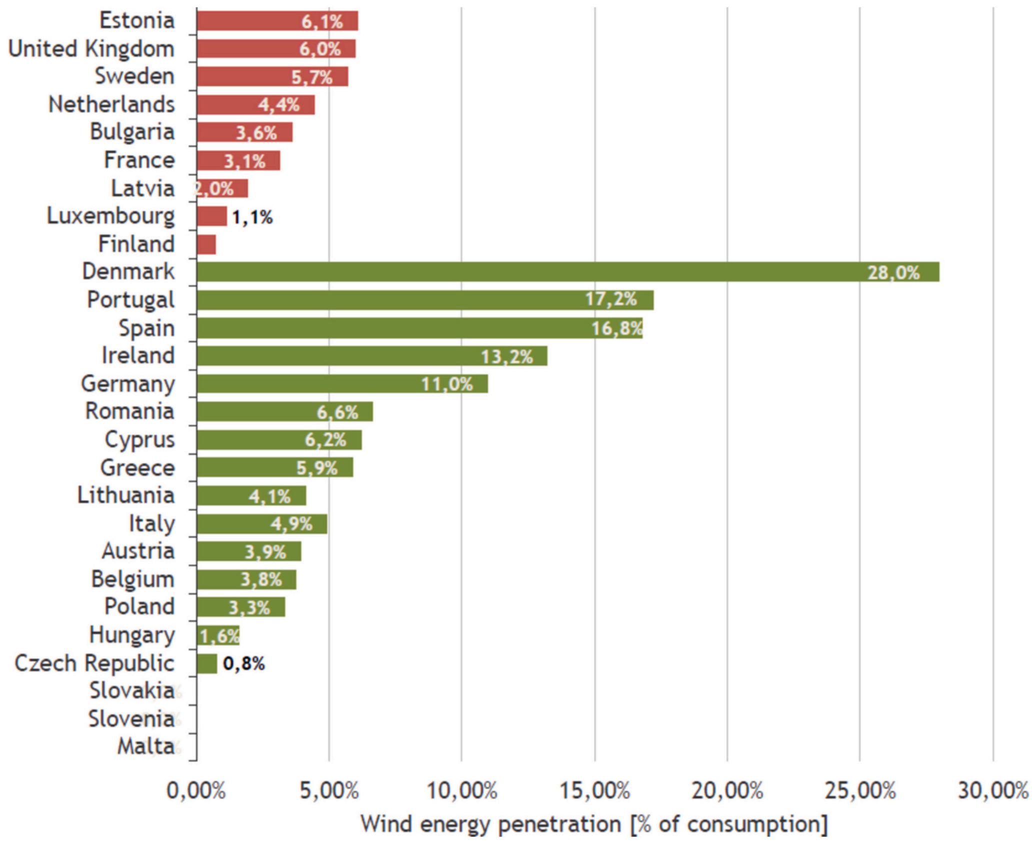

Fig. 3. Dispatch priority has real implications of wind penetration on European grids. Compiled by [65].

Hence, the basic fact is that without RAM, system effectiveness calculations or something similar, LCOE analyses are misleading. Worse, as will be demonstrated in Section 6, this misleading usage of LCOE is common today, which ultimately implies that the LCOE numbers are essentially understating the true costs of supplying an energy unit to a customer with a reliability that would satisfy that customer.

External costs are also usually ignored or defined out from the scope of the study at hand. The importance is exemplified by the fact that the annual externalities for energy and transport is equivalent to 28.7 % of global Gross Domestic Product (or USD 24.7 trillion) whereas energy efficiency and demand response can reduce these by USD 312 billion [63]. Thus, we should estimate the costs more accurately by taking *all* costs into account.

Finally, the War in Ukraine has demonstrated that energy security is an important factor that should be incorporated into the LCOE metric [64] because different energy sources will have different security profiles. The authors find that in the period October 1, 2021, to December 31, 2022, Europe spent an extra EUR 517–831 billion in excess of market costs due to higher prices, with a best estimate of €643 billion, which comes on top of the EUR 908 billion spent by European governments on energy related infrastructure and policies. With some risk of overlapping expenditures, the total is at least EUR 1 trillion or more. Indeed, the energy crisis cost Germans EUR 1500 bn [53]. Essentially, risk is also a metric to be included, not just technical risks discussed next but also supply risks. Security is actually completely missing in Table 1, which should be added. Thus, policy is misguided as far as these numbers are concerned. Also, when the IPCC uses such estimates, the energy mix in their scenarios is misguided.

3.4. The politics of dispatch priority

Concerning the energy mix, an interesting aspect is the dispatchability of the energy sources. VREs are today given so called dispatch priority, and EWEA [65] writes that:

"Priority dispatch is the obligation on transmission system operators to schedule and dispatch energy from renewable generators ahead of other generators as far as secure operation of the electricity system permits. The purpose of Priority Dispatch is to further the objective of the integration of renewable energy into the electricity system to promote sustainability and security of supply for Europe".

The result is that all other energy sources must handle the residual variations of demand minus VRE production, which subsequently results in less load and higher unit cost per energy unit (MWh). It should be noted that dispatch priority can also be influenced by constraints, costs and other system issues.

Some people argue that the priority dispatch of VREs is due to the lower marginal costs of VREs, and that VREs will therefore win the action in the day-ahead market. This is only partly true, and Haelg [66] shows on the level of which technologies win which concessions, that there are many factors determining the outcome of auctions even if we compare different VREs to each other.

In Fig. 3 we see the markets where the Transmission System Operators (TSO) opposed VREs (red) but was politically forced some ten years ago, and those that accepted VREs (green). Why they opposed is not explained, but this author assumes they were worried of the situation shown in Fig. 2.

The Netherlands and the UK are two interesting countries where the TSOs clearly objected the introduction of large scale VREs. What happened? A clue may be offered by the fact that "Advocates assert that because the renewable energy transition is fundamentally a political struggle, efforts to shift from fossil fuels and decarbonize societies will not prove effective without confronting and destabilizing dominant systems of energy power" [67]. We can only speculate as to the impact, if any, such political struggles have had on the usage of the LCOE given its importance for political decision-making.

Table 2
How different reputed organizations handle the contentious issues of LCOE. Note that 'Taxes' is not a contentious issue but handled differently and therefore included in the table. The disadvantage of including taxes is that the LCOE estimates become regionalized, they will change according to prevailing politics, they become incomparable over time and they may mask the technology cost performance unless the LCOE without taxes is also provided. This author therefore prefers to calculate the LCOE ex taxes.

Organization	Selected Publication	Reliability	Availability	Maintainability	Capability	Life-span	Discounting	Taxes	System perspective	Alternative approach	Shortcomings communicated
Bloomberg New Energy Finance	[28,139]	No	No	No	Yes	Yes	Project WACC	Yes	No	No	Yes, partly, and a disclaimer
European Commission	[140]	No	No	No	No	Technology specific	Multiple WACC	No	No	No	Yes, partly
Institute of Renewable Energy (IRENA)	[3]	No	Yes	Only the costs, no system impact	Yes	25 years	Multiple WACC	No	No	No	Yes, partly
Intergovernmental Panel on Climate Change (IPCC)	[2]	No	No	No	No	Project specific	Multiple WACC	Carbon prices	No	LCCE and LCCC	Yes, partly
International Energy Agency (IEA)	[4]	Described only	Described only	Only the costs, no system impact	Described only	Technology specific	Multiple WACC	Tax credits and carbon prices	No	VALOCE	Yes, partly
Lazard's	[141]	No	No	No	No	Technology specific	After-tax cost of equity (12 %)	Detailed tax credits	No	With and without subsidies	Yes, partly, and a disclaimer
National Renewable Energy Laboratory (NREL)	[142]	No	No	No	No	Technology specific	Multiple WACC	Detailed tax credits	No	No	Yes, partly
US Energy Information Agency (EIA)	[143]	Described only	Described only	Only the costs, no system impact	Described only	30-years	WACC at 4.2 %	Detailed tax credits	Transmissions are included	LACE	Yes, partly

4. The contentious issues

The contentious issues must be discussed to understand the reconceptualization and the critical evaluation of how reputed organizations calculate the LCOE. Some of the contentious issues are a matter of judgment whereas others are more fundamental.

4.1. Life-span and discounting

Many calculate the LCOE so that the 'LCOE excessively penalizes projects with longer expected lives and with higher discount rates' [68]. Typically, a 20–30-year recovery period is chosen [3,69], but a simple direct comparison is misleading when the competing technologies last half a century or more. Thus, there is an implicit focus on new energy source development and not existing power generation [70], but new technologies may not provide enough productivity gains to offset the advantage existing power plants have concerning lower fixed costs [69].

When it comes to the choice of discounting rate itself, financial realities and lifespan must be taken into account. For example, MIT [71] uses 7.9 % in the context of nuclear power. However, 7.9 % is unrealistic over the lifespan of any long-term investment. In fact, Estrada [72] finds, based on the very large Dimson-Marsh-Staunton dataset which covers 19 countries over 110 years, that "…average across the 19 countries in the sample, stocks provided investors with an annualized real return of 4.7%, 3.8 percentage points higher than that of bonds (0.9%)". US stocks from 1802 to 2002 had a total annualized return of 7.9 % [73] whereas a third data set across 17 countries from 1900 to 2005 averaged approximately 5 % [74]. In short, investors cannot expect the same Return On Equity (ROE) for generational investments than for more short-term investments, which makes sense because of the powerful time diversification, see [75].

Assuming 7.9 % as ROE, 4 % interest rate on debt, 23 % corporate tax rate[2] and a 30 %/70 % equity/debt ratio, as used by World Nuclear Association [76] for example, then the Weighted Average Cost of Capital (WACC) becomes 4.5 %, and WACC is frequently used as discounting rate. Canada uses the real Social Discount Rate (SDR), with an individual's SDR being in the 3.5 % to 4.5 % range [77] for nuclear power.

These historical data shows that using discounting rates that fails to take the lifespan of the asset into account are outright unscientific. As Hue et al. [78] eloquently state; "Discount rates are simple and simplistic, readily available to anyone and dangerous in both the 'wrong hands' and the 'right hands'". Another challenge is that discounted value drops rendering almost anything beyond 30 years uninteresting. Even with just 2 % discounting the residual value after 50 years will be 37.2 %, yet assets with a long lifespan often operate well beyond 50 years. For long-term projects, Hue et al. [78] recognize that "…using discount rates alone is limited and it is more optimal to consider cashflows using a robust stochastic process".

Therefore, we must discuss discounting more because underestimating the discounting rate (using the WACC, for example) by only 2 percentage (8 % instead of 10 %) points leads to overestimating its present value by 25 % [79]. Surveys show that most firms use only one single discount rate to value all of their projects [80]; a behavior that Krueger et al. [79] label as the 'WACC fallacy' due to the bounded rationality of managers. The result is that organizations fail to properly adjust for risk in their valuation of investment projects, leading to value-destroying investment decisions. The WACC fallacy is a failure to account for project-specific risk, which is particularly damaging when the organization has to decide between heterogeneous projects – such as in energy. Most energy projects are project financed in an effort to manage risk, which means that it is the project WACC that counts and not the

[2] The average OECD corporate tax rate is 23.3 % in 2020, calculated with data accessed 2021-01-27 from https://stats.oecd.org/Index.aspx?DataSetCode=TABLE_II1

corporate WACC, and because it allows off-balance sheet transactions so that the debt used to fund the project does not appear on the company's balance sheet and has no impact on its credit rating or borrowing capacity.

From Table 2, in Section 6.2, we see that on the surface, the reputed organizations avoid the WACC fallacy by using multiple WACCs or project specific WACCs. Yet, when we investigate the details for the two organizations discussed in Section 6.2, they both make errors. Both use real WACCs whereas IEA [4] uses a single real WACC but at different values.

Understanding the mistake of using the real WACC, is more difficult. A current interest rate has three components: 1) inflation, 2) risk premium and 3) real interest rate (as if there is no risk) [81]. While the 'real interest rate' is not observable, it is used here to bring forth a crucial distinction. Based on his extensive work, Fisher [82] proved that:

$$1 + RATE = (1 + rate) \times (1 + i.) = 1 + rate + i + i \times rate \quad 3$$

Where RATE is the nominal interest rate, i is the expected inflation rate and 'rate' is the real interest rate. Unfortunately, it has become customary to ignore the product term (because it is small) at the end of Eq. (3) [81,83] so that.

$$RATE = rate + i \quad 4$$

This simplification has real implications observable in real life particularly for large projects because under certain conditions, using real or constant prices overvalue the cash flow appraisal where the conditions include among others the existence of taxes and depreciation [84]. The correct usage of Eq. (3) leads to the general conclusion that we should use the deflated WACC rather than the real WACC to discount real cash flows, and the nominal WACC to discount nominal cash flows [81], which is consistent with the findings of Bradley and Jarrell [85].

Calculating the deflated WACC is unnecessary when the simplest solution is to use the nominal WACC because we have information on the nominal values for the cost of debt and the return to equity whereas real values for these parameters are not observable [81]. Also, the deflated WACC requires a constant inflation rate over time which is also not observable on timescales relevant for assets with long lifespan. Thus, the mathematical elegancy of using the deflated WACC and real terms is difficult to defend for longer time horizons.

The impact of this finer distinction when using Eq. (1) for calculating the LCOE, is that the LCOE will be artificially low (and wrong) since prices are normally larger than costs. Eq. (1) is therefore inconsistent with financial theory (structurally invalid) and should be abolished for that reason alone.

Using the nominal WACC requires an explicit modeling of inflation in the net cash flow throughout the lifespan of the asset. This can arguably be difficult, and certainly uncertain, but the most important effect is that using the revised LCOE formula in Eq. (8) discussed later in Section 5, it is the sum of the energy produced that will dominate and hence lower the LCOE for assets with long lifespan. Using Eq. (8) will therefore lower the LCOE for hydro and nuclear compared to using Eq. (1), and hence improve their competitiveness significantly compared to assets with shorter lifespan such as wind and solar.

Thus, assets with a long lifespan should have a different discounting rate than short-lived assets. Unfortunately, the IEA [4] and many others use a standard lifespan and discounting rate *across* projects independently of technologies but they are open to use different lifespan and discounting rate *between* projects. Hence, financing is seen as strictly a project-related matter and they ignore parts of financial realities and technology. This was not a problem in the past when life-spans were 30–40 years or more for all assets, but this is no longer the case.

Some studies, see Table 2 later, make this distinction whereas other simply provided a range of discounting rates and the readers are left to make their own interpretations. The former is obviously more correct from a LCC perspective whereas the latter provides at least the reader with some understanding of the sensitivities. Also, despite using the same discounting rates and lifespan across technologies the residual value, also known as terminal value, is ignored for assets with longer lifespan.

All the reputed organizations reviewed in this paper ignore the residual value, and it is highly why since the residual value concept is well known. The effect, however, is that current LCOE analyses favor short-lived assets at the expense of assets with a long lifespan. The same problem occurs when introducing energy storage systems with particularly short lifespan [86].

The residual value concept has a long-standing tradition in project- and equity valuations [87]. A general idea is to find a finite present value of all those cash flows that lie after the certain period [88], i.e., the lifespan of the asset with the shortest lifespan in our context. There are five types of residual values [89] and they require judgment – liquidation value, book value, multiple value, zero growth perpetuity and constant growth perpetuity. Two of them are relatively straightforward – book value and zero growth perpetuity. The others three are difficult to apply for our purpose because they are based on market valuations of the asset itself which obviously will be difficult 25 years into the future. The most important is to be consistent. However, there are significant challenges [90] due to the stochastic nature of the free cash flow.

In our case, the focus on residual costs simplifies the assumptions. The residual cost will most likely depend on the Long-term Marginal Cost (LMC), see Section 4.4, more than the depreciation of the asset in question. The residual cost will therefore consist of depreciation costs plus LMC in perpetuity. This perpetual cost can be estimated by using the standard perpetuity formula for residual value [91]. Unfortunately, there is much confusion around valuation and how to handle inflation, and Cornell et al. [92] demonstrates that even a 2 % inflation can have major impact. In particular, inflation drives a wedge between replacement cost and depreciation, and for that purpose the Net Cash Flow (NCF) where NOPAT is Net Operating Profit After Tax is defined as [85]:

$$NCF = NOPAT - Replacement\ cost + Depreciation \quad 5$$

Combining these insights and reducing the NOPAT to the LMC, we obtain the following estimate for the residual cost in perpetuity for a company starting in year n + 1:

$$Residual\ cost = NCF_{n+1}\frac{\left(1+\frac{g}{ROIC}\right)}{(WACC - G)} \tag{6}$$

Where g is the inflation adjusted growth, G is the nominal growth and ROIC is the Return On Invested Capital. There is no reason to expect that an asset will grow in any other way than by inflation as we focus on residual costs and the asset can grow only through major investments. Hence, g = 0, and G is inflation (i). Furthermore, annual depreciations will fall to almost zero unless there are Major Refurbishment Costs (MRC). Such costs are incurred sporadically and must therefore be calculated according to a plan and discounted to year n at WACC. For nuclear power plants, e.g., a major refurbishment normally takes place after ca 30 years [93], and the costs may run up to 60 % of initial investment in real terms. Thus:

$$Residual\ cost = \frac{LMC}{(WACC - i)} + EB_n + MRC_{n+x<N} \tag{7}$$

Where:

n is the LCOE analysis horizon, which is determined by the asset with the shortest lifespan.

N is the technical lifespan of the asset in question.

LMC is the Long-term Marginal Cost per unit energy occurring after year n. For power plants where fuel is important, using a running average to smooth out fluctuations may be useful [86].

EB is the end book value (initial investment minus all depreciations including year n).

WACC is the nominal Weighted Average Cost of Capital for the asset.

i is the inflation, preferably for the given type of technology if

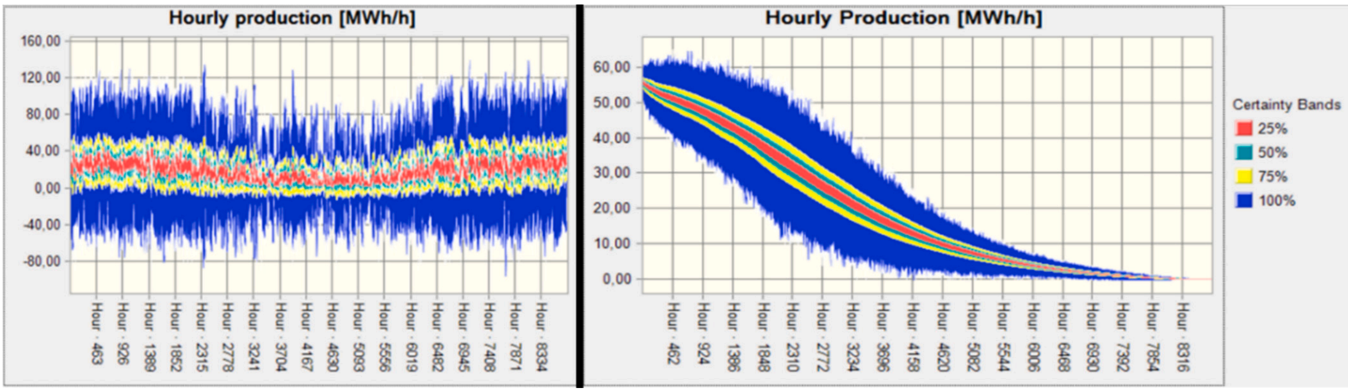

Fig. 4. Simulation of Bessakerfjellet wind power plant in Norway based on data from 2012 through 2021. The PCF is 31.8 % deterministically, or 34 % with a standard deviation of 0.5 %.

available.

$MRC_{n-x<N}$ is the Major Refurbishment Cost at a year between n and N, n + x discounted to year n using the nominal WACC.

The interesting fact is that the discounting model does not take into account exogenous parameters that fundamentally alters the cashflow. As such, it fails to handle the fundamental aspects of cost of capital. The cost of capital can be seen as an opportunity cost and must be at least equal to the profitability of the alternative opportunities that have been given up [94]. For example, Reinhart and Rogoff [95] have examined the output consequences of 100 financial crises over more than 150 years and they prove the crises take a long time to handle (often 5–10 years) and cause major losses. The last major financial crisis in 2007–2008, still lingers five to six years after the onset and only Germany and the United States (out of 12 countries) have reached their 2007–2008 peaks in per capita income.

This perspective is important to include as actuaries do. Indeed, they hold that 'discounting cashflows to a single liability value on which to make funding and investment decisions suggests a greater degree of certainty about the future than can be justified' arguing in favor of robust stochastic process [78]. For pension funds of various types, life insurers and other long-term investors that comprise the world's largest asset owner's, the conservatism embedded in this realistic view is paramount. The degree of risk they are willing to assume depends on who the investor is, the nature of their funding sources, what constraints they face, and for what purposes they are holding the asset. Indeed, by converting future cash flows to the present, it can be shown that the discount rate is the inverse of the investment return [78]. Therefore, discount rates must be consistent with investment returns and the type of investors, and residual costs must be used to account for difference in lifespan. To use a standardized rate and lifespan is both structurally- and performance invalid.

4.2. Modeling capacity

The supply of capacity and the demand for capacity and the differences in measures is critical [96];

'Cost' is a measure of resource consumption that related to the demand for jobs to be done whereas 'expense' is a measure of spending that investigates the capacity provided to do a job.

Critically, we must match the supply of capacity to demand and not the other way around [96], and for that reason dispatchable assets have a major advantage over non-dispatchable assets. Unfortunately, the priority dispatch of VREs incurs costs for dispatchable assets by overriding the cost causation principle in the cost management literature which states that 'costs should be assigned to those using a resource' [97]. This principle has also been adopted in rate estimations for utilities since the classic text of [98], and has caused discussions lately, see for example [99,100].

With capacity/expense numbers being found in the general ledger [101], we must discuss capacity in greater detail and [102] offer these definitions:

1. Theoretical capacity – the highest level of work a process or plant can complete using a 24/7 operation with zero downtime.
2. Practical capacity – the theoretical capacity adjusted for nonproductive time required for maintenance, set-ups and an allowance for breakdowns.
3. Normal capacity – the average, expected capacity over a defined period of time.
4. Budgeted capacity – the capacity that the budget is based on.
5. Actual capacity utilization – this is the capacity utilized.

Following the debate sparked by Cooper and Kaplan [103] over correct cost assignment, the Institute of Management Accountant (IMA) in the US and Society of Management Accountants in Canada issued in 1996 the Statement on Management Accounting (SMA) where they made it abundantly clear that theoretical capacity or maximum practical capacity is to be used [104]. Using maximum practical capacity is often the chosen approach [101]. Today, the common approach when calculating the LCOE is using the normal capacity, but this is consequently incorrect.

To the knowledge of this author, the above cost vs expense distinction is lost in grid costing analyses. Regardless, the discussion above begets the question 'what is the maximum practical capacity for a VRE?' Currently, PCF is the most common approach for assessing capacity. The PCF is the actual output divided by theoretical output and calculated over suitable periods. Some of these approximations are reasonably accurate [105], but they miss short-term and annual variability and availability compared to demand [106]. Hence, the PCF is not the best, but it is simple and can be used for quick screening [32].

Calculating capacity key metrics for VREs is challenging and there exists many methods, see [106]. The purpose is to say something about the contribution that a given generator makes towards meeting the electric load [107]. The problem with the PCF is that it is only approximately right, and with high time resolution it can be completely wrong.

An example illustrates the point. In Fig. 4, we see the simulated performance using Monte Carlo simulations of one of the larger wind power plants in Norway, Bessakerfjellet. 10 years of hourly data has been used to estimate seasonal variations and hourly variations. Then, the wind power plant performance has subsequently been simulated for 10,000 years. The two different plots represent two different ways of modeling. Note that the installed capacity is 57,5 MW distributed at 25 wind turbines.

The plot to the left is organized chronologically starting with the first hour in the year to the left and the last hour to the right. This approach

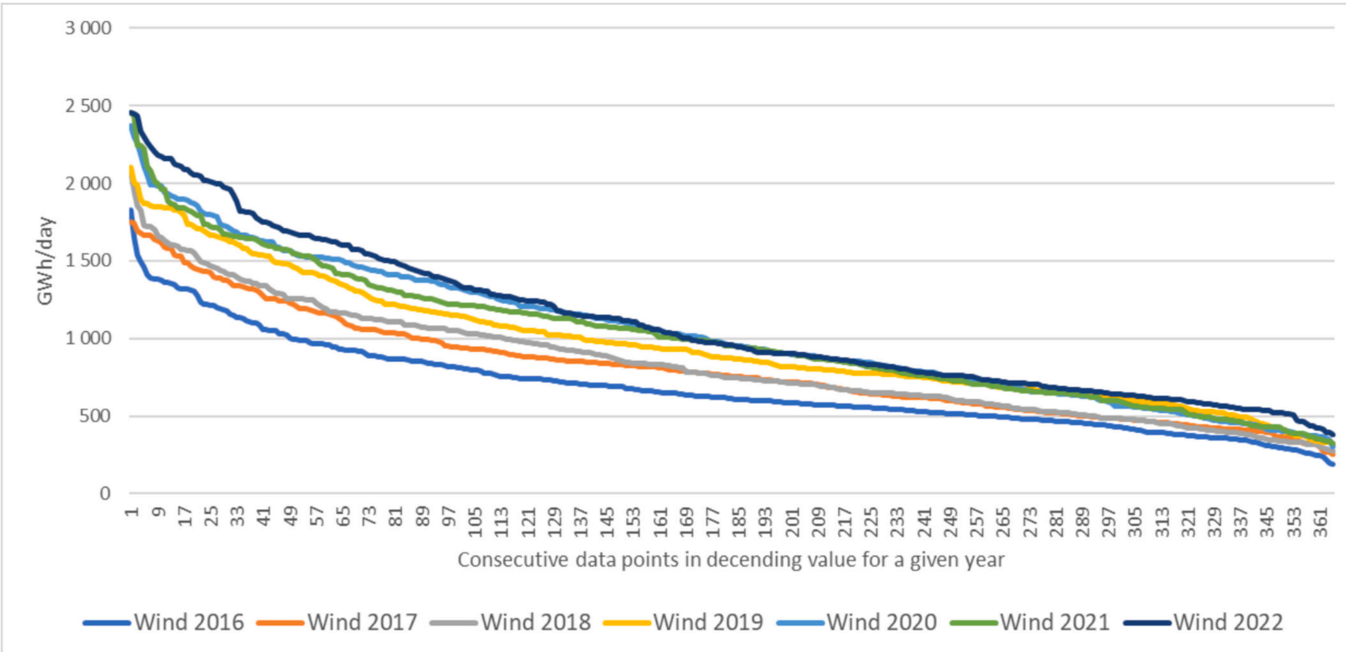

Fig. 5. Wind power plant production in EU-27 from 2016 through 2022, organized according to descending production per hour from left to right. Authors calculations based on data from www.energy-charts.info and www.ourworldindata.org.

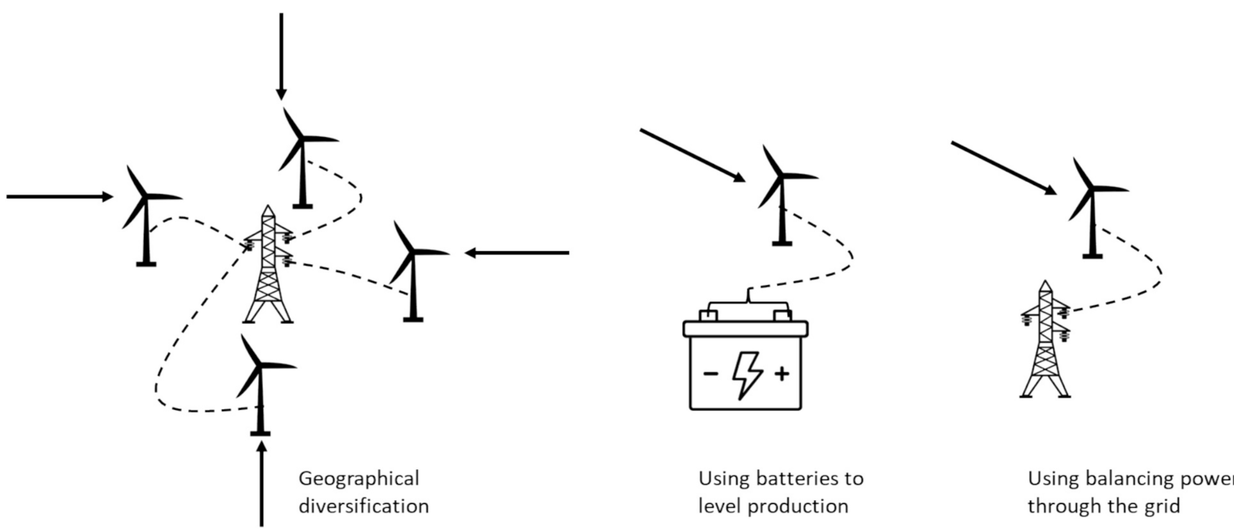

Fig. 6. The three different approaches to secure output from VRE. Source: [113].

mirrors reality both in that Summer does have the lowest production and also that the probability of zero production is there all year. However, the normal distribution used leads to impossible negative productions, which means that normal distributions are not ideal fit, which can be solved but it creates more complexity in terms of modeling and communication.

The plot to the right is organized in descending order. This plot is easier to read because we see that zero production is found to the right starting from hour 8316, which means that the zero production is about 444 h or more than 18 full days (the data sample contains three full leap years but it is defined as 365 days for all years by ignoring the 29th of February in 3 out of 10 years). This plot, however, offers no insights into the temporal aspects – the summer variations are lost. However, the uncertainty becomes less and the reliability is easier to show graphically for communication purposes. Clearly, the reliability for a wind power plant is close to zero, and realistic modeling must include either balancing power or storage.

This is also true for all the wind power production in the EU-27 and ignore bottlenecks and other practicalities in the grid, see Fig. 5 – there is always low production some days for any given year. Furthermore, despite a 48 % increase in wind power capacity [108] in the period, the number of days with very low production remains. Hence, expanding the grid by increasing capacity improve reliability but not to a satisfactory level for a modern economy. The average PCF in the period is only 23 % and at the days with the lowest production, the production corresponds to only 7 % of the maximum practical capacity.

The capacity issues of VREs have been known for a long time, so Madaeni et al. [61] undertook a comprehensive study and one of the best is the Effective Load Carrying Capability (ELCC) method. The ELCC of a power generator represents its ability to effectively increase the generating capacity available to a utility or a regional power grid without increasing the utility's loss of load risk [109]. For instance, a

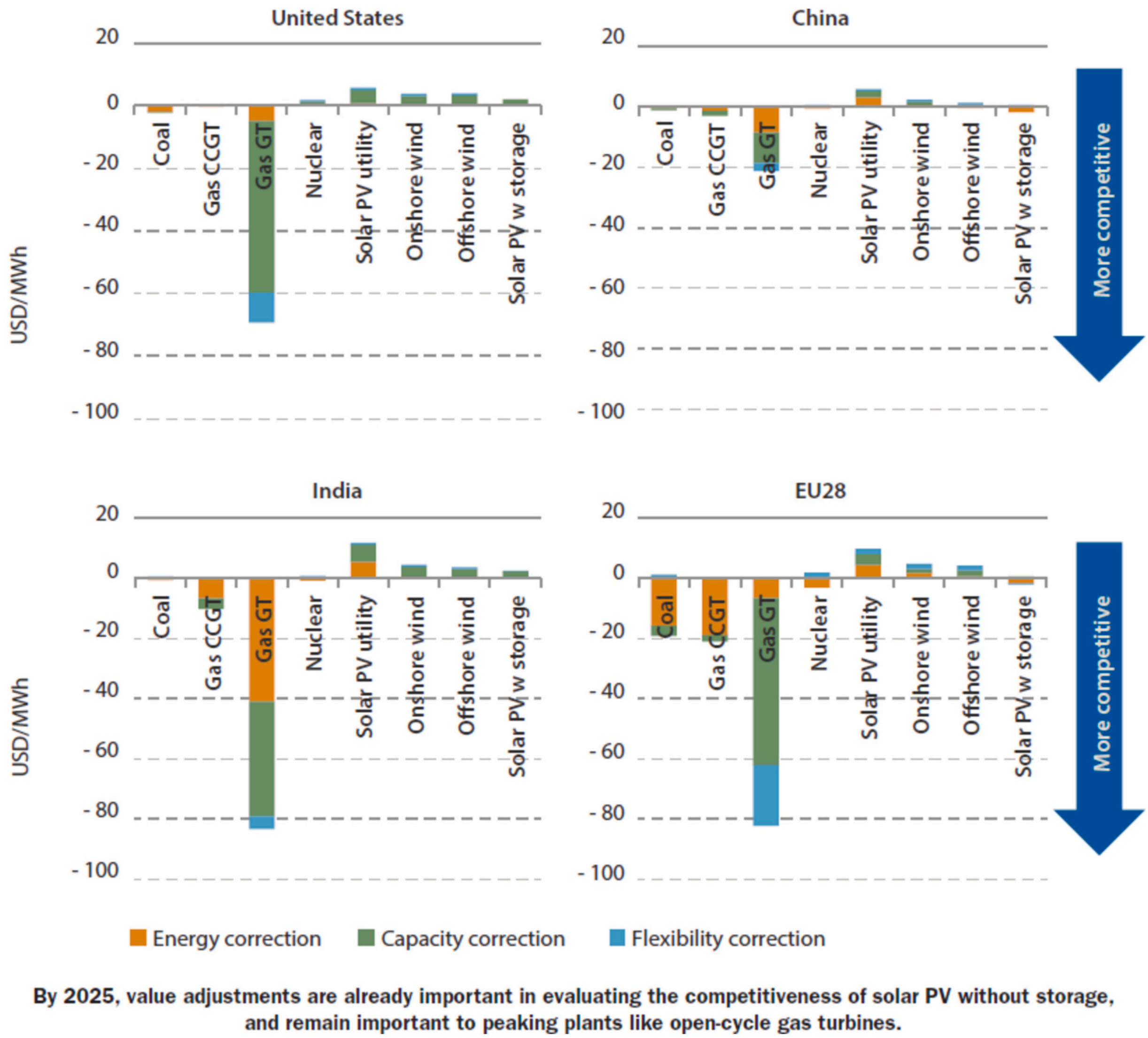

Fig. 7. Simulated value adjustments by technology and region based on WEO 2019 Stated Policies Scenario, 2025. Source: [4].

utility with a current peaking capability of 2.5 GW could increase its capability 2.55 GW with the same reliability by adding 100 MW PV, provided the ELCC of the 100 MW PV is 50 MW, or in relative terms, 50 % [110]. The disadvantage of this approach is that it is relatively computationally heavy as an iterative computation is used [61]. It is similar to capacity value, which measures the fraction of the time VREs can produce electricity that can be actually used on the grid [30].

According to Rocha-Garrido [111], the mean ELCC of wind power was merely 11.5 % for the PJM Interconnection from 2009 through 2017. The mean PCF of wind for the USA in the same period[3] was 33.2 %. However, when we compare the ELCC to the results in Figs. 4 and 5, we understand that it is certainly too optimistic on asset level for wind power. What is sure, is that the current usage of the PCF as an annual mean is highly misleading [112].

To have a meaningful discussion on reliability, thus implies that we must find a way to secure a reliable output beyond the financial energy market. This author has identified three possible ways for renewable energy sources to secure an output (see Fig. 6): 1) geographical diversification and trade, 2) energy storage and/or 3) balancing power and trade. A combination is probably the most likely in a real grid. Note that while trade (export and import) can come to the rescue at times, history has shown that political entities will take care of their own members first rendering trade potentially risky.

The geographical diversification approach is based on spreading the assets so far apart that they will ideally have uncorrelated weather systems. This is only theoretically possible as we see from Fig. 5. The real situation is actually worse if bottlenecks and other practicalities were included.

The second approach of using Battery Energy Storage Systems (BESS), which can also contribute to the overall grid management through peak-shaving [114], giving lower costs [115], less emissions [116] and better quality [117].

The third approach is the most common approach today. In 26 OECD countries, fossil energy has historically been most common balancing power from 1990 to 2013 studied [118]. Unfortunately, with a fossil balancing power, wind can never produce an overall sustainable energy supply [112]. Hence, from a sustainability point of view, the balancing power must be non-fossil, although from a techno-economic point of view it must have a significant share of dispatchable power. The impact on the LCOE is significant as shown in Section 6.3.

In all three cases, the approach is to first set reliability targets, then take the various uncertainties into account and simulate the capacities

[3] See https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_07_b

required and finally estimate the costs. For LCOE estimates to stay structurally valid, different energy sources must be assigned the true maximum practical capacity and VREs must therefore explicitly have a balancing−/backup plan or else the reliability is zero for an industrialized society that needs power at all times.

For a small community that has not become accustomed to electric power, however, it is completely different. Despite the fact that an average American consumes 50 times more energy than an average Bangladeshi and 100 times more than an average Nigerian, relatively poorer villagers in Mali and Uganda are willing to pay about ten times higher price than the typical prevailing price in developed countries [119]. Therefore, off-grid solar PV is an excellent technology, which explains why it has lately faced record investments (although being still only 1 % of grid-connected Solar PV) [120]. The exact same Solar PV installation off-grid will therefore have a lower LCOE than in the grid because the RAM performance is acceptable per definition.

4.3. The segregation of value from costs

In economic theory, value refers to 'the worth of something to its owner' [34] either by its usage or in exchange, whereas cost refers to '… a resource sacrificed or forgone to achieve a specific objective' [121]. It is the exchange perspective of value that counts in markets due to their transactional nature, which is closely related to the price of goods as determined by their supply and demand – a perspective we owe to Alfred Marshall's work [122]. However, prices never fully capture value [123], which is why opportunity costs and externalities exist as discussed initially.

The challenge of VREs is that production can quickly change the supply while the weather itself can also simultaneously impact demand directly. Also, grid with high shares of VREs increasingly face overproduction to an extent that the VREs are curtailed, i.e., paid not to produce, and negative prices occur in the market. According to IEA [124], "Although VRE curtailment is increasing overall, the share of curtailed wind and solar PV generation remains relatively low, ranging from 1.5% to 4% in most large renewable energy markets".

Therefore, the 'value factor' of VRE generation, interpreted as the average market value of VRE energy divided by the average price of electricity, tends to decline with increasing VRE penetration [125,126] as observed many places in the world, see [48,49]. If the integration cost of VRE is taken into consideration, the optimal shares of wind and solar energy in a grid will decline significantly [127,128], and the Asset LCOE increasingly differ from the System LCOE.

To capture these value losses of VREs for high levels of penetration, other approaches have been developed such as Levelized Avoided Cost of Energy (LACE) [129] and Value-Adjusted LCOE (VALOCE) [4]. The LACE approach is providing similar improvements as VALCOE [4]. However, unlike IEA [4], US EIA [129,130] does not mention grid reliability or any such physical parameters. LACE seems predominantly a financial approach. The only limitations US EIA [129] highlights are factors such as technology cost and -performance, financing, and system configuration because they are represented by approximations that collapse local, regional, technological, and temporal variations in these factors to facilitate computational tractability and efficiency of the model.

The VALOCE was developed for the 2018 World Energy Outlook [4], and it is the measure used today that is most closely related to the System LCOE [49]. Its motivation is driven by the fact that LCOE has major problems in estimating the costs of VRE [4]. For each technology, the VALCOE combines the LCOE for a given year with the value of the multiple system services it can provide in the context of the regional power mix at that time.

More specifically, the VALCOE captures the value of three system services: energy value, flexibility value and capacity value by technology. The flexibility value, which is set to become more important as the share of variable renewables rises in regions around the world, encompass non-energy ancillary services required in power systems, such as primary- and secondary reserves, frequency regulation and synchronous inertia [4]. Fig. 7 shows the consequences for some technologies in some regions. The main weakness of VALCOE is its reliance on price signals to represent true value. Mixing value with costs is not a good practice although the VALCOE does capture some aspects of the opportunity costs ignored by the Asset LCOE. Furthermore, RAM is ignored.

Indeed, Blazquez et al. [131] identify the "Renewable energy policy paradox" which states that "promoting renewables –in liberalized power markets creates a paradox in that successful penetration of renewables could fall victim to its own success". This situation is a clear indication that LCOE is no longer serving its purpose well, i.e., poor performance validation. Moreover, to resolve the renewable energy policy paradox proper costs must be assigned to VREs [131]. This author concurs.

4.4. The zero marginal cost fallacy

In economics, the marginal cost is the change in the total cost that arises when the quantity produced is incremented (the cost of producing additional quantity) [132]. Concerning energy, this statement needs an additional qualification. The quantity must be uniform, i.e., 1 kWh of electricity is independent of its source. With different energy sources having different RAM, the very premise of the argument is flawed.

What is true, however, is that the marginal cost for the individual VRE asset is approximately zero, but this is far from the marginal cost impact on the system being approximately zero. Since the primary objective for a grid is to serve as a system, it is the latter view that counts. This may explain why the TSOs opposed VREs in the early days, as discussed in Section 3.4 – they knew that the marginal system costs would be far from zero.

As discussed earlier, the LMC perspective is very interesting for assets with a long lifespan. For nuclear power plant projects, it has therefore become customary to develop financing schemes where risks are shared, or managed, to better represent its relation to society at large. Traditionally, this was achieved through large, vertically integrated sovereign-backed utilities but this is now changing [133]. New financing models are being developed where private financing play a large role and risks are shared between various parties [134]. The shared risk approach lowers the cost of capital substantially partially shifting the focus from the investment costs to the LMC. Indeed, the LMC is the primary decision criterion for lifespan extension of nuclear assets [29].

A similar approach was used in Norway when the country rapidly expanded hydro power from 1960 through 1990. The asset cost was as high as 1.5–2.5 NOK/kWh per year (using 1982 av. reference) for most power plants,[4] but the argument for investing in hydro was the low LMC [135]. At the time, inflation would marginalize the initial investment costs, which illustrates the importance of including inflation particularly when comparing assets with very different lifespan. With the increase in financialization since the 90s [136], however, the World Bank [137] wrote that there is a sharp decline in construction of hydro projects, not due to any change the fundamental economic benefits that have arisen in the context of private hydropower, but rather due to the new low-risk projects that are not capital-intensive, with short financing and quick returns are favored.

5. Correct usage of the LCOE concept

There are a number of best practices that can be drawn out from the literature. The list below is a short summary, and it will serve as criteria for evaluation of how the reputable organizations calculate the LCOE:

[4] In 1986, USD 1 was on average NOK 7.40, which today would be NOK 20.27 in 2023. Source: Norges Bank.

1. The LCOE must be chosen as an asset level metric or a system level metric. If it is an asset-level metric no comparison between different asset types must take place. None of the reputed organizations have resisted the temptation of comparing different power plant technologies.
2. System stability must be explicit either through RAM calculations or explicit addition of balancing/back-up power to secure a predefined performance which is acceptable to the market in question. When non-synchronous assets drive the grid up to the synchronization limit, the non-synchronous assets must be curtailed and assigned the cost in line with the cost causation principle.
3. The consequences of dispatch priority must be modelled and made explicit. For example, the current priority given to VREs implies that dispatchable energy sources must operate at lower capacity utilization than maximum practical capacity. This is a system cost incurred by the VREs and should be assigned accordingly since the system need the dispatchable energy sources due to system stability and/or for balancing/backup.
4. The capacity model must be based on maximum practical capacity and in accordance with items 2 and 3 above. Capacity with no economic value, i.e. unused capacity, must be assigned according to the cost causation principle. Preferable resolution is 1 h resolution or better to capture the technicalities of ramping and grid reserve, see [112] for details.
5. Lifespan and discounting factors must be seen together and attuned to the investor types that normally invest in a certain power plant technology. The WACC must therefore be either project-specific or technology specific and calculated in nominal terms, which implies that inflation must be included in the model. Residual costs must be calculated if applicable.
6. Value should not be used in the model unless it is the best way of modeling the alternative cost for the system. If an LCOE model handles the items above reasonably well, there is no need to adjust the LCOE using value metrics.

Given the intricacies of energy systems, it is clear that a simple formula cannot assess all economic issues equally well. Therefore, the formula should be made simpler but with a structurally valid description:

$$\mathrm{LCOE} = \frac{\sum_{t=1}^{n} \frac{Net\ cashflow_t}{(1+r)^t} + Residual\ cost_N}{\sum_{t=1}^{N} E_t} \tag{8}$$

Where:

N The technical life-span of the asset with the *longest* life.

n The time horizon of the asset with the *shortest* lifespan.

Net cashflow The sum of all expenses including those at the system level (unless it is an Asset LCOE, from cradle to grave, for the asset with the shortest lifespan minus residual cost beyond n. Inflation must be modelled.

WACC The nominal weighted average cost of capital for the project unless it is explicitly stated that it will be financed on the corporate balance sheet (applied to small projects only).

E_t The amount of electricity produced annually in year t [MWh], modelled in a proper production model for each year t that takes into account all the criteria discussed.

Externalities must be listed explicitly and discussed in relation to the LCOE.

Testing this approach is essentially what Emblemsvåg [32,52] have done, but thorough empirical testing requires more work. An example is provided in Section 6.3. The purpose here is to show that reconceptualizing the LCOE is possible without making it too technically difficult to use.

6. Evaluation of how some reputable organizations calculate LCOE

Reputable organizations, particularly governmental organizations, have a special responsibility in publishing material that is as truthful as possible. The evaluation performed will therefore first focus on the structural validity of the LCOE calculations provided by the reputable organizations as judged by how they handle the contentious issues. Then, the actual calculations will be reviewed to say something about the performance validity of their work. Finally, a case is presented in Section 6.3 which will underline the total argument of rethinking the LCOE.

6.1. How the reputable organizations handle the contentious issues

How the reputable organizations handle the contentious issues is summarized Table 2, and discussed in no particular order. This author has not had the possibility to review all the publications from these organizations, but have selected some representative works for illustration. Furthermore, Table 2 focuses only on the more advanced aspects of LCOE because all reputed organizations have good cost data, power capacity factors (PCF), uncertainty estimates, and they perform sensitivity analyses and handle inflation.

We start by pointing out the simple fact, observed from Table 2, that the organizations themselves handle the contentious issues differently. That noted, we must add that the overview presented in Table 2 is to some extent unfair because several of these organizations offer different reports that have some variations on how the LCOE is being calculated, but to make Table 2 readable it must be abbreviated to the extent that some aspects may be lost. Table 2 should therefore be interpreted with care, and the most important lesson is that the system aspects are always ignored, grid connections/transmission costs are sometimes included (mostly not) and balancing/backup costs are ignored, which means that the LCOE numbers fail basic LCC RAM requirements and are inherently incomparable, but provide a realistic Asset LCOE estimate.

Starting with the Institute of Renewable Energy, we generally find

Table 3
The LCOE estimates of the two intergovernmental agencies in 2020 USD.

Organization	Institute of Renewable Energy (IRENA) [144]	International Energy Agency (IEA) [4]	Difference	Difference to IRENA
Onshore wind [USD/kWh]	0.041	0.050	0.009	22 %
Offshore wind [USD/kWh]	0.084	0.088	0.004	5 %
Solar PV [USD/kWh]	0.057	0.056	−0.001	−2 %
Hydro [USD/kWh]	0.044	0.072	0.028	64 %
Geothermal [USD/kWh]	0.071	0.099	0.028	39 %
Bio energy [USD/kWh]	0.076	0.118	0.042	55 %
Challenge for comparison	Multiple WACCs used. Average real WACC is 5 % in OECD and China. LCOE average is used.	Real WACC of 7 %. LCOE median is used.		

Table 4
– Deterministic capacity modeling. Authors calculations using data provided in the paper.

Percentiles	Wind [MWh/h]	Probability weighted wind production [GWh]	Wind OPEX [MUSD]	Curtailment [MUSD]	Gas production [GWh/yr]	Gas Costs [MUSD]	Total costs [MUSD]
1 %	3.0	26.4	0.3	4.7	477.3	33.4	38.37
5 %	5.4	44.6	0.5	4.5	459.1	32.1	37.10
10 %	7.1	55.7	0.6	4.3	448.0	31.4	36.32
15 %	8.3	62.1	0.7	4.2	441.6	30.9	35.87
20 %	9.5	66.7	0.8	4.1	437.0	30.6	35.54
25 %	10.9	71.3	0.9	4.0	432.4	30.3	35.22
30 %	12.1	74.4	1.0	3.9	429.3	30.1	35.01
35 %	13.6	77.4	1.2	3.8	426.3	29.8	34.80
40 %	15.2	79.9	1.3	3.6	423.8	29.7	34.62
45 %	16.8	81.0	1.4	3.5	422.7	29.6	**34.55**
50 %	18.3	80.3	1.6	3.4	423.4	29.6	34.59
55 %	19.9	78.5	1.7	3.2	425.2	29.8	34.72
60 %	21.3	74.8	1.8	3.1	428.9	30.0	34.98
65 %	22.7	69.7	2.0	3.0	434.0	30.4	35.34
70 %	24.0	63.0	2.1	2.9	440.7	30.8	35.80
75 %	25.2	55.1	2.2	2.8	448.6	31.4	36.36
80 %	26.5	46.4	2.3	2.7	457.3	32.0	36.97
85 %	27.9	36.6	2.4	2.6	467.1	32.7	37.65
90 %	29.7	26.0	2.6	2.4	477.7	33.4	38.39
95 %	32.1	14.1	2.8	2.2	489.6	34.3	39.23
99 %	36.1	3.2	3.1	1.8	500.5	35.0	39.99

Table 5
Asset level data. Source: [4].

	Median	Min	Max
LCOE Gas [USD/MWh]	70.0	50.0	107.0
LCOE Onshore wind, global [USD/MWh]	50.0	29.0	140.0
CAPEX, Wind Onshore Norway [USD/MW]	964.0	559.1	2699.2
OPEX, Wind Onshore Norway [USD/MWh]	9.8	5.7	27.6
LCOE Onshore wind, Norway [USD/MWh]	31.0	18.0	86.7

low VRE Asset LCOE estimates. In the entire report on LCOE [3] (and later reports), the word 'reliability' is mentioned only five times and none in the context of LCOE. 'System effectiveness' is not mentioned at all. Essentially, they calculate LCOE without satisfying the RAM- or the system effectiveness requirements in LCC. The report does not discuss common caveats with the LCOE calculations, or they are very difficult to find, and the report can therefore easily lead to misinterpretations concerning the costs of VREs.

Unfortunately, the National Renewable Energy Laboratory (NREL) seems to follow the same line although with greater variations. For example, Smart et al. [138] provide the definition and rationale for the Baseline Offshore Wind Farm established within IEA Wind Task 26 – Cost of Wind Energy. Yet, 'reliability' is not mentioned, but 'availability' is. Overall, the LCOE discussion is poor in terms of system perspective but good on asset level. Again, the LCOE estimates are misleading. The report from the European Commission in Table 2 has the same issues.

The IEA has published perhaps the best report, see [4]. Not only are they clear on limitations, but they also provide two alternative approaches for overcoming the limitations of the LCOE approach "…well understood by the experts…". The approach they have developed themselves is referred to as Value-Adjusted LCOE (VALCOE), and they also refer to the Levelized Avoided Cost of Energy (LACE) developed by the US Energy Information Administration (EIA) as discussed earlier. However, their claim that the LCOE is"…a uniquely transparent and intuitive metric…" in the foreword seems unfounded, to say the least.

However, they fall into the WACC fallacy like everybody else. Unfortunately, they also set the system boundary at the asset level, but they are clear about that. Using this, the LCOE numbers can be adjusted as shown in Fig. 7, but questionable, as discussed in Section 4.3. Unfortunately, the system part is still elusive even with the improved approach offered by IEA [4] on asset level.

There are, however, some organizations that are professional enough to describe the issues and make correct disclaimers. The IPCC is one such organization, see [2], although it is unclear to what extent they have adjusted their analysis to the facts that standard LCOE analyses are highly misleading concerning VRE.

The other, Lazard [141], professionally states that "This analysis does not take into account potential social and environmental externalities or reliability-related considerations" and the same message and more is reiterated in the summary. Similarly, Bloomberg New Energy Finance (BNEF) is using a finance model including all project costs, excluding grid connection costs, to achieve a given equity return rate in the absence of subsidies [28]. The model is referred to as the EPVAL (Energy Project Asset Valuation) Model which captures the timing of cash flows, development and construction costs, depreciation, multiple stages of financing, interests and tax implication of long-term debt instruments and more. BNEF's LCOEs are furthermore derived from their monthly and semi-annual surveys of equipment buyers/sellers, combined with estimates about natural resource availabilities in countries [139].

Hence, it is difficult to escape the conclusion that the LCOE estimates used for public policy around the world are misleading. However, as we see, reputed organizations are to some extent aware of most of the shortcomings. For example, the NREL writes[5] straight out that "Importantly, LCOE does not capture the economic value of a particular generation type to the system and therefore may not serve as an appropriate basis for comparisons between technologies. For example, LCOE ignores attributes that can vary significantly across different technologies (both in terms of capability and cost) such as ramping, startup, and shutdown that could be relevant for more detailed evaluations of generator cost and value to the system". Hence, a part of the LCOE 'abuse', as it were, is therefore that many users are not aware of the shortcomings presented by the analysts they use. There is in other words also a matter of communication, education or training in addition to the calculation related issues discussed earlier.

The second problem is that the 'abuse' is not remedied. The analysts have failed in their task of educating and training their customers as well as reconceptualizing the LCOE accordingly to keep it relevant. This is not very helpful for improving policymaking, modeling, technology evaluations and the like. Therefore, this paper suggests some contributions to the improvement of the LCOE that should be relatively

[5] Accessed 2022-05-16, see https://atb.nrel.gov/electricity/2021/definitions#lcoe

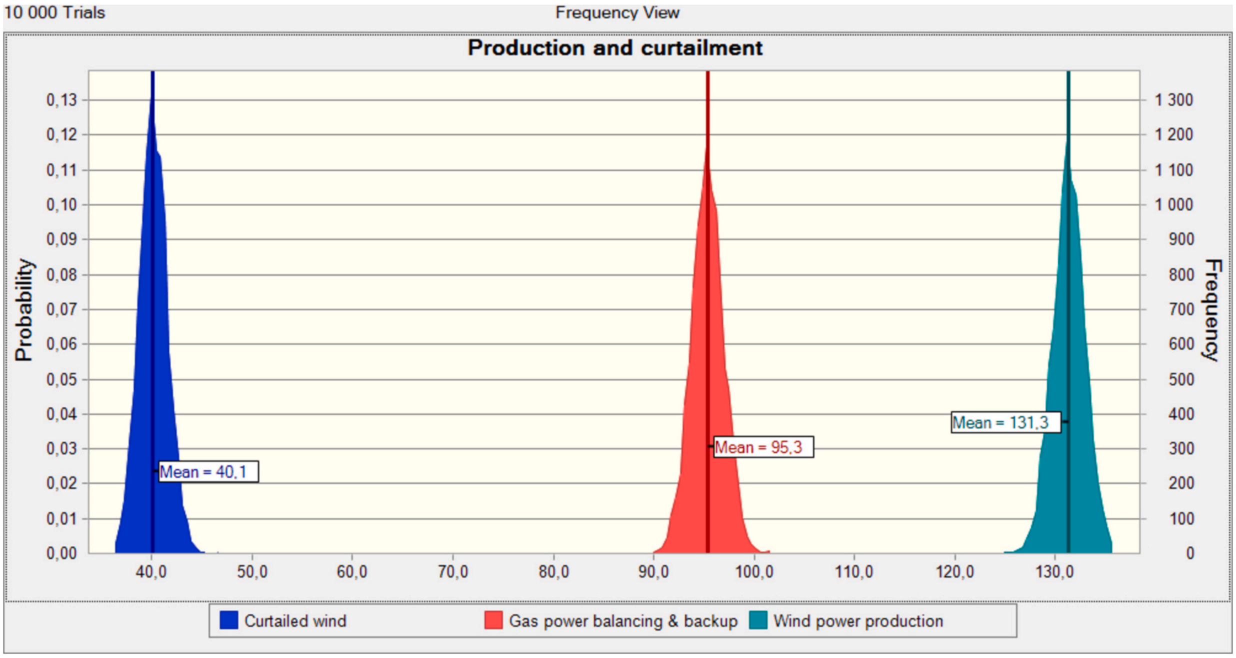

Fig. 8. Production profile [GWh/yr] of Bessakerfjellet when all uncertainties are included except downtime for maintenance and repair.

straightforward to implement and communicate.

First, policy documents must take care in explaining some of the commonly caveats to contextualize the LCOE numbers better. For example, they could consistently refer to the 'Asset LCOE' to highlight that the system perspective is not included. The same is true when we discuss marginal costs. Also, a section titled 'Limitations' would help to identify the limitations.

Second, the calculations, starting with the formula itself, should be rethought as discussed in Section 5 and illustrated in Section 6.3. It can be done without undue complexity. There is no excuse.

Third, the idea that value and costs are synonymous is untrue in unregulated markets. It has only worked out in the short-term, which is quite irrelevant for LCOE. Therefore, to value-adjust the LCOE does not make sense other than in an attempt of capturing some of the opportunity cost in the short term under the assumption that these costs can be limited to value losses.

Fourth, when calculating the LCOE, a performance target in terms of reliability must be defined and communicated otherwise we are comparing apples and oranges and essentially converting individual risks and -costs into systemic risks and -costs without understanding the impact.

6.2. *The differences in asset LCOE estimates for the different reputable organizations*

The interesting question after Section 6.1 is how much difference there is in the Asset LCOE estimates from the reputed organizations. Those that have a regional focus will obviously result in different estimates than those with a global focus. It is therefore most interesting to discuss the three intergovernmental agencies in Table 2 that all have a global focus but with some methodological differences. Unfortunately, the IPCC issues Asset LCOE estimates infrequently making a direct comparison unfair. In Table 3 we therefore find the differences is the estimated Asset LCOE of the two agencies that issue such estimates regularly. Table 3 contains only the estimates that most people, certainly policymakers, would pay attention to.

There are several interesting observations to be made from Table 3. First, IRENA [144] uses a weighted average whereas IEA [4] uses the median. This can certainly produce some differences in the estimates. Also, the Asset LCOE estimates from IEA [4] are almost always higher. It is unlikely to be due to the median being different than a weighted average but more due to the differences in approach.

Second, the three dispatchable energy sources – hydro, geothermal and bio energy – have the greatest differences. Geothermal is understandable due to the small sample size which can make the outcome very sensitive to the selection of projects. Bio energy is very location specific concerning the availability of biological waste, however, bio energy is a relatively large contributor with many assets. The law of large numbers should therefore make the estimates converge for all else being equal. The difference is therefore most likely due to methodological differences and some data differences.

The fact that the greatest difference is hydro is particularly interesting because it is a CAPEX intensive asset with a long lifespan. Here, the outcome is probably dictated by significant differences in the method such as the choice of WACC, and data.

Finally, the difference in onshore wind is large in percentages, but it is still less than 0,01 USD/kWh. This is probably within the accuracy of the Asset LOCE calculations but also impacted by the issues just discussed. Obviously, the Asset LCOE does not represent the true costs in any fair way, and directly comparing it to the three dispatchable energy sources in the same table – which is inescapable since they are frequently found in the same table – makes it easy to conclude that onshore wind is the least costly energy source among those analyzed. Yet, we have all the issues discussed earlier.

In short, all the six points in Section 5 are violated in various degrees. The structural- and performance validity are also suffering.

6.3. *The case of onshore wind in Norway*

The difference between the approach suggested in Section 5 and the current approach is most easily shown using onshore wind as an example. The analysis will take a system view, using a balancing power/backup power to secure RAM performance within targets and priority dispatch for the onshore wind asset. Gas power is chosen in line with the empirical fact that gas is the most commonly used balancing- and backup power for renewables in 26 countries of the Organization for Economic Co-operation and Development (OECD) countries [118]. The lifespan is set to 25 years in agreement with IRENA [3] but with a 7 %

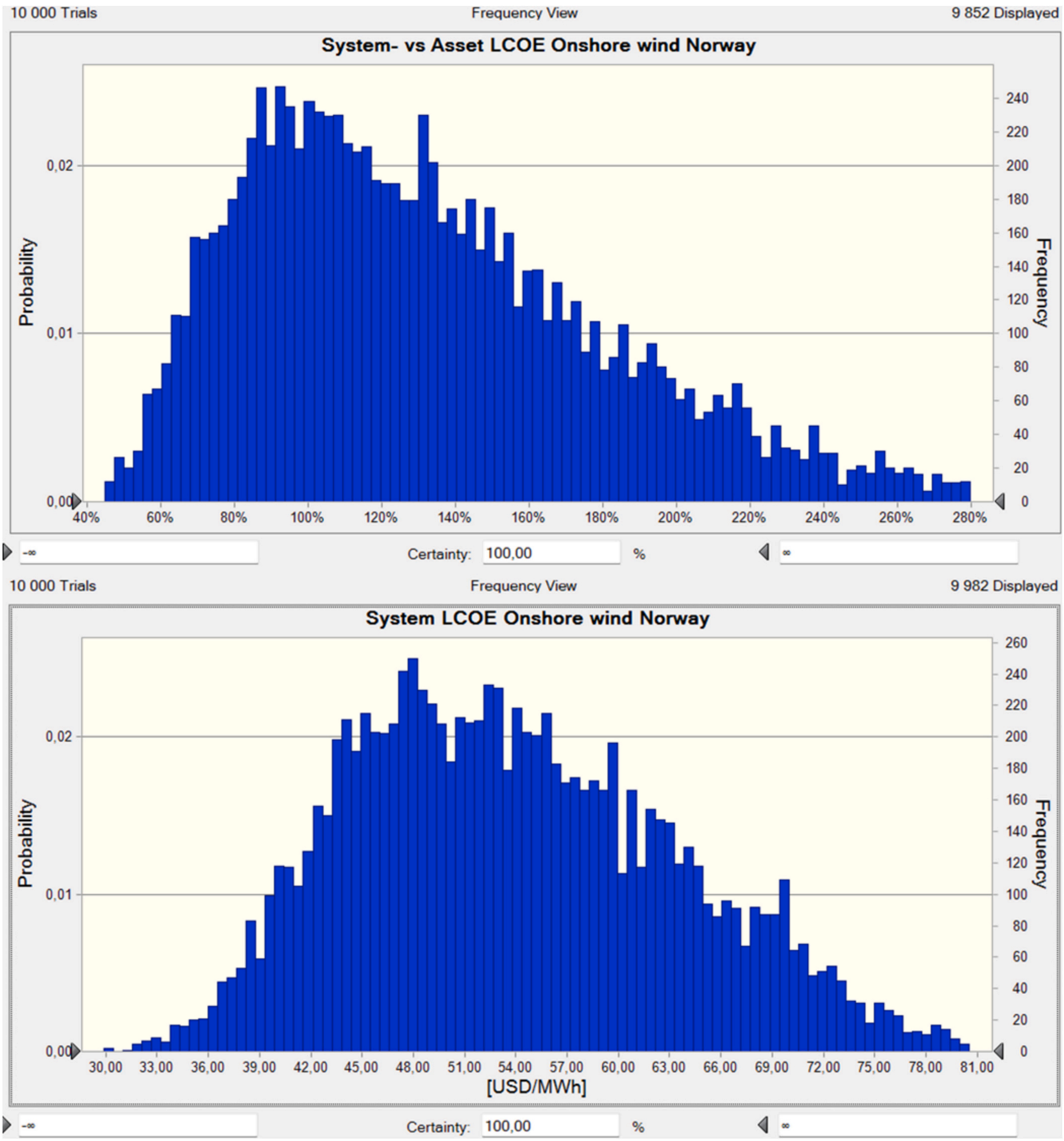

Fig. 9. Onshore wind Norway LCOE and System LCOE vs Asset LCOE when maximum practical capacity is 45 % of nameplate capacity, all uncertainties included.

nominal WACC. The cost numbers are from IEA [4]. Inflation is assumed to be 2.5 % with a minimum of 2.0 % and a maximum of 4.0 % modelled as a triangular uncertainty distribution. The debt is assumed to be handled through a series loan with 4.0 % interest.

The capacity model should balance the cost of the balancing power/ backup power, on the one hand, and curtailment costs, on the other hand. This will maximize the economic result for the asset. Due to the fact that wind varies for year to year, also, we must use multiple years to model a likely capacity profile. This profile is uncertain, which together with all the uncertainties in the input parameters, can be handled using Monte Carlo simulations. For simplicity Bessakerfjellet wind power plant in Norway can serve as an example. The actual production is discussed in Section 4.2.

In Table 4, a simple deterministic capacity model is presented to assess what kind of performance level should Bessakerfjellet aim for. The model essentially tries to determine the maximum practical capacity that will provide the lowest total cost. We see that the 45 % capacity provides the lowest deterministic cost. Note that some parameters are not symmetric which mean that an uncertainty analysis of the same model can reach a somewhat different result.

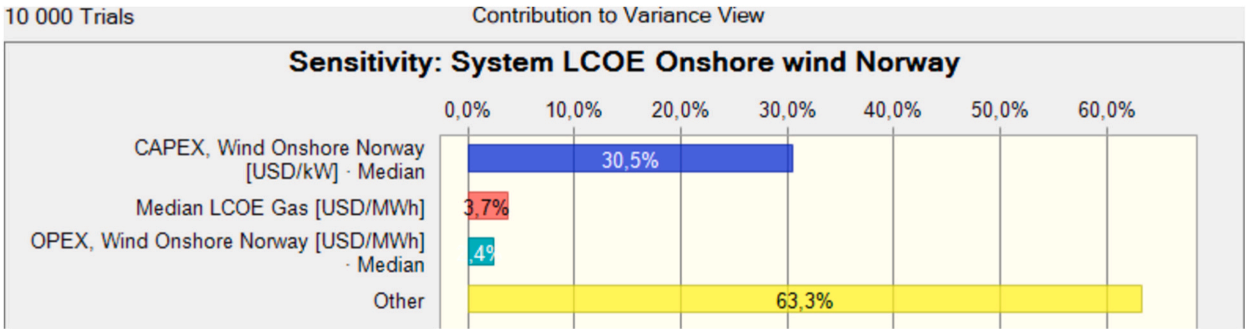

Fig. 10. Sensitivity chart for System LCOE Onshore wind Norway.

The cost data are presented in Table 5. The Asset LCOE for Onshore Wind, global, is used to estimate the maximum and minimum values for Norway since they were not provided. Also note that using the LCOE for gas as a proxy for the price of balancing/backup power in the market is optimistic. Most likely it will be more expensive. Finally, maintenance downtime is ignored and possible synchronization issues.

The disadvantage of having to guarantee performance is that if the wind asset produces too much it will have to be curtailed. Therefore, in Fig. 8 we find 3 categories – actual production delivered to the grid, the amount of balancing/backup of the assets and the amount of wind curtailed. The total costs have been minimized by scaling the performance commitment to only 45 % of installed capacity effectively turning Bessakerfjellet from a 57.5 MW installation to a 25.9 MW installation. As long as wind is cheaper than gas, this makes sense. Using the 57.5 MW as reference, the installation would be more gas with wind than wind with gas.

Deterministically, the LCOE becomes 36.6 USD/MWh which is 19 % higher than the Asset LCOE in Table 5. Once uncertainties are included the results become as shown in Fig. 9. We see that the uncertainties pull the LCOE estimate upwards to 53.8 USD/MWh, which is 34 % higher than the deterministic asset LCOE.

The fact that the maximum practical capacity was attuned to 45 % of maximum capacity also had an impact on the LCOE. Using the same model, we can also estimate the LCOE if the maximum practical capacity is set to maximum capacity, and then the deterministic LCOE becomes 39.9 USD/MWh whereas when uncertainties are included it becomes 47.9 USD/MWh (54 % higher than Asset LCOE) and the System LCOE becomes a maximum of 3.5 times the Asset LCOE.

From Fig. 10, we can also identify the drivers of the System LCOE. Clearly, there are a handful of economic parameters of great importance, but the large share of the 'other' shows that the actual production profile is very important. To avoid unnecessary curtailment and gas power purchase, a flat and even wind production profile is very beneficial – not the amount of wind per se in a year.

7. Limitations and future work

Given that reputable organizations have a disproportionate influence on the usage of the LCOE approach, there is perhaps a Gresham's law in that good work is driven out by bad work as Chick [145] alluded to in the context of the financial crisis when she suggested that "bad economic theories drove out good ones", or as Boorstin [146] remarked, "In our ironic twentieth-century version of Gresham's law, information tends to drive knowledge out of circulation". Exactly for this reason, reviewing the work of these reputable organizations is perhaps much more important. Reputable organizations *should* be discussed.

The risk this work potentially suffers from as a review, is therefore the risk of being seen an uninformed about the work of experts that are hard to find in the multitude of publications. To avoid that, there are a number of detailed discussions on the contentious issues to both critically review the issues, but to also show that some issues are not as simple as initially meet the eye – also for experts. Discussing many papers would not necessarily add extra value.

The purpose of Section 6.3 is to show both the importance of a System LCOE analysis but and that it does not have to be so difficult that we should abandon the LCOE concept altogether. The LCOE has many great advantages, mentioned initially, so it is better to remedy it than to abolish it. This insight is perhaps the most important insight this paper has to offer – the LCOE can really be remedied as discussed in details, without becoming overly technical and therefore end up suffering from 'paralysis by analysis'. There is, in other words, no excuse for improving the LCOE metric from an Asset LCOE to a System LCOE.

Future work should focus on executing many cases like the one presented in Section 6.3 using different parameters to estimate which parameters are truly important and why, and which can be ignored when, if at all. This will provide additional insights that can be used for further improvements.

8. Concluding remarks

This paper has tried to shed light on the intricacies that impact the true costs of VREs as measured using the LCOE. Some issues are relatively well known in the literature, but to varying degrees and largely under-communicated to policymakers and practitioners alike. Indeed, not a single reputed organization evaluated in this paper offers LCOE estimates that are true to the total LCC costs of an energy source. Fortunately, most of these organizations explain well most of the shortcomings, but they always ignore the critical ones related to RAM/performance criteria, the relations between discounting, lifespan and investor types and residual costs.

The same reputed organizations could have made some obvious improvements to overcome their shortcomings. A first step is to rethink it since its origin in the world of public utilities with dispatchable energy technologies no longer exists.

Secondly, to use the same life-span and discounting across technologies is not only illogical due to the nature of different energy technologies, but it also fails to take into account the various investor categories that would invest in the different energy sources and violates financial theory. While we can appreciate the effort of improving the LCOE by adjusting it by value estimates, it is important to understand it's limitation. System LCOE must become the ultimate goal, and it can be achieved relatively well as shown here without very complicated calculations.

Finally, reliability must become an explicit part of LCOE calculations, to avoid introducing alternative costs that others must assume – costs that the Asset LOCE approach today treat as externalities.

In any case, it is important to keep the LCOE simple enough to secure its popularity and usage, but to amend the most common shortcomings and communicate clearly limitations and correct interpretations. One measure does not fit all purposes, which is exactly why it is important to keep the LCOE focused on its true purpose – to estimate the discounted life-cycle cost per energy unit for a given energy technology, with given performance requirements over its entire life-cycle, cradle to grave.

CRediT authorship contribution statement

Jan Emblemsvåg: Writing – review & editing, Writing – original draft.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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