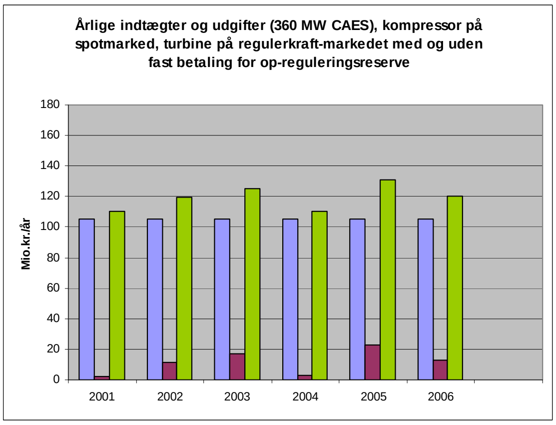
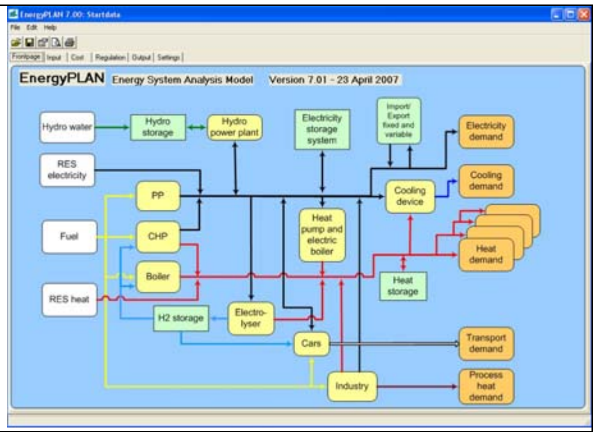
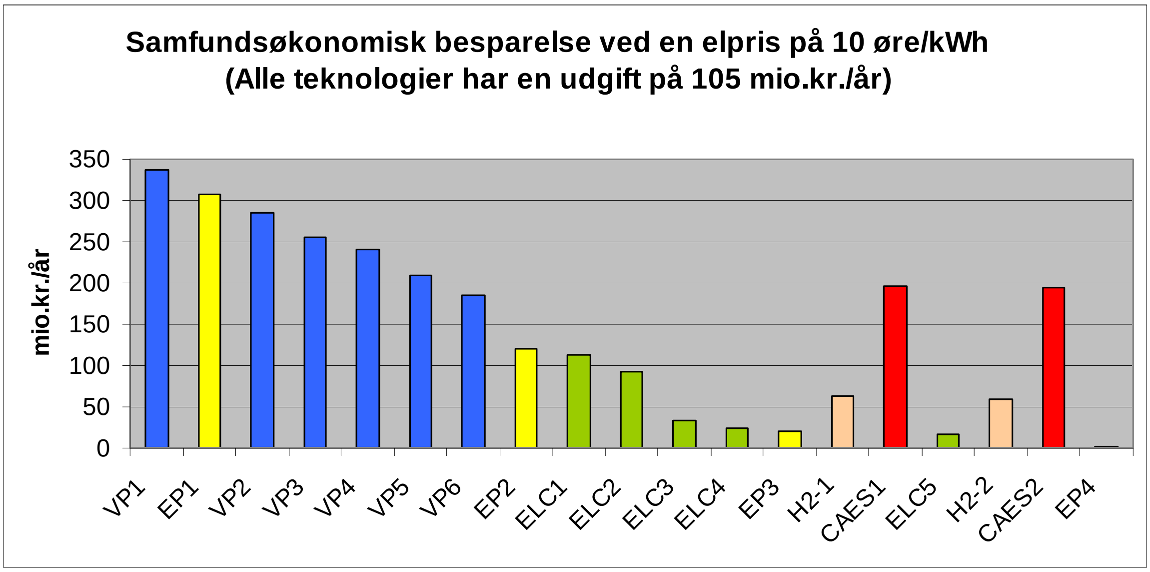
CAES

Muligheder for anvendelse af Compressed Air Energy Storage for ellagring i fremtidens elsystem

PSO-F&U-projekt nr. 2005-1-6567
Del-rapport I







Henrik Lund og Georges Salgi
Aalborg Universitet, juni 2007

Indhold

1. Formål, opgaveformulering og konklusion

Det overordnede formål med projektet er jf. projektbeskrivelsen at afgøre om CAES (Compressed Air Energy Storage) vil være et økonomisk og energimæssigt godt alternativ til andre typer af el-lagring og reguleringsmetoder i forbindelse med el-overløb i fremtidens el-system.

Det samlede projekt omfatter jf. projektbeskrivelsen såvel en samfundsmæssig analyse med udgangspunkt i det samlede danske energisystem som en selskabsøkonomisk analyse med udgangspunkt i det enkelte CAES-anlæg. Og i de efterfølgende drøftelser med Energinet.dk er der lagt vægt på at inddrage såvel spotmarkedet som regulerkraftmarkedet.

Projektet er udført i et samarbejde mellem DTU, DONG og AAU, og har været grebet an fra to vinkler. AAU har således primært stået for den samfundsøkonomiske vinkel, mens DTU primært har stået for den procesmæssige vinkel. Nærværende rapport redegør for AAU's arbejde, som hermed afsluttes. DTU vil efterfølgende foretage en samlet afslutning af projektet. I forbindelse med et øget fokus på regulerkraftmarkedet er der yderligere indgået aftale om at inddrage Energi og Miljødata (EMD) i projektet. En del af resultatet af AAU's analyser er en specifikation af, hvad EMD især bør fokusere på.

AAU's bidrag består dels i udvikling af model og metoder til systemanalyser af et CAES-anlæg samt implementering af disse metoder i energisystemanalysemodellen EnergyPLAN, og dels i en række konkrete analyser på to CAES-anlæg beskrevet af DTU og DONG.

De nævnte analyser, metoder og modeller er beskrevet i en række artikler og notater, som vedhæftes som uddybende bilag. Og i det følgende gives et samlet resume af arbejdet.

Konklusion

Konklusionen på de samfundsmæssige systemanalyser er, at set isoleret "i forbindelse med el-overløb i fremtidens el-system" kan CAES-anlæggets systemmæssige og samfundsøkonomiske værdi ikke opveje investeringsomkostningerne. Og der findes en række alternativer, der udviser væsentligt bedre økonomi. Men hvis CAES-anlægget samtidigt kan erstatte et tilsvarende kraftværk, er der potentiale for en positiv økonomi.

Konklusionen af de selskabsøkonomiske analyser er, at det er helt afgørende for CAES-anlæggets selskabsøkonomi, at det opnår fuld fast betaling for opregulering. Herudover skal der tjenes penge minimum på regulerkraftmarkedet og også gerne en kombination af spot- og regulerkraftmarkedet. Analyserne viser, at over den historiske periode fra 2000 til 2006 ville det have været muligt at opnå gennemsnitlige indtægter på årligt 125 mio.kr. ved at drive turbinen på regulerkraftmarkedet og kompressoren på spotmarkedet. Og potentialet for udnyttelsen af begge markeder ligger på 190 mio.kr./år. Disse indtægter skal sammenholdes med en årlig fast udgift på 105 mio.kr./år for en levetid på 30 år og en realrente på 3%. De 190 mio.kr./år er et maksimum, som ikke vil kunne realiseres i praksis, idet det skal sikres, at turbinen hele tiden er til rådighed for regulerkraftmarkedet. Det anbefales derfor, at EnergyPRO-modellen anvendes med henblik på at vurdere, hvor langt man i praksis vil kunne komme i nærheden af denne indtægt uden at sætte den faste betaling over styr.

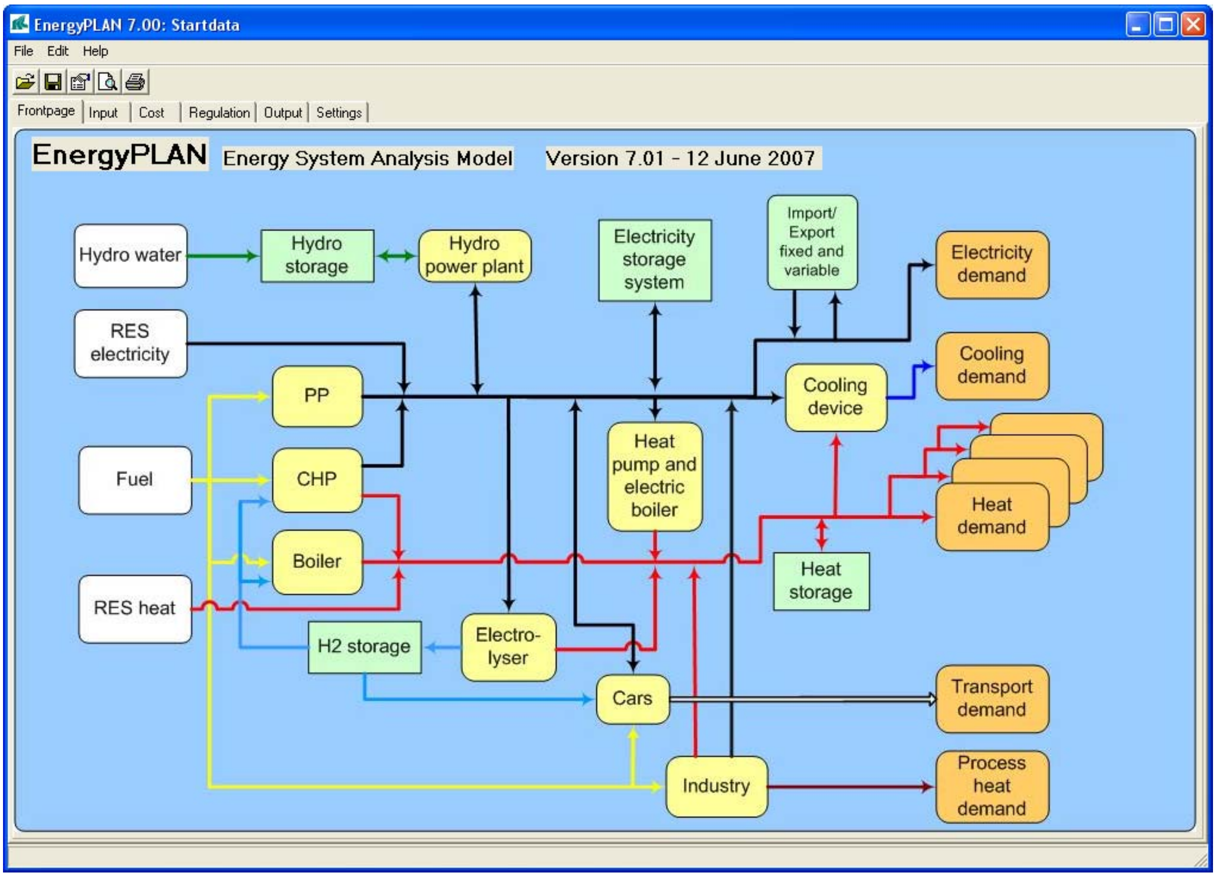
2. Model og metode (Udvikling af EnergyPLAN-modellen)

EnergyPLAN-modellen er en energisystemanalysemodel, der kan gennemregne komplette nationale energisystemer time for time med vægt på balancer mellem elproduktion og elforbrug såvel som øvrige energibalancer i systemet.

EnergyPLAN-modellen kan således udregne omfanget og den tidsmæssige placering af eventuelle el-overløb. Og modellen kan udregne konsekvenserne af forskellige investeringer i teknologier til at nyttiggøre et sådant el-overløb.

EnergyPLAN-modellen kan simulere en række forskellige reguleringsstrategier herunder en regulering, der svarer til den nuværende markedsregulering, hvor det enkelte værk optimerer sin selskabsøkonomiske indtjening gennem handel på Nord Pool-markedet. EnergyPLAN-modellen kan udregne de samfundsøkonomiske konsekvenser af en sådan optimering.

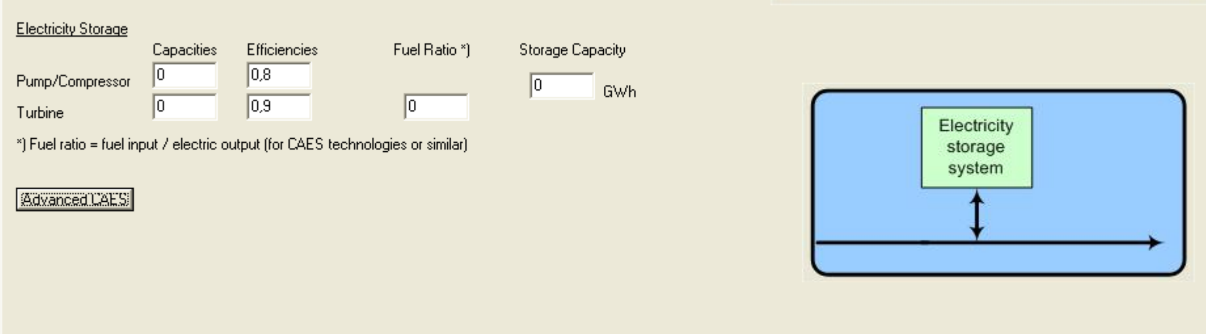
EnergyPLAN-modellens energisystem er vist i nedenstående principskitse, der samtidig er forside på computerprogrammet. EnergyPLAN-modellen kan frit downloades fra hjemmesiden: www.EnergyPLAN.eu. Samme sted kan man finde en komplet dokumentation af modellen i den version (7.0), som de efterfølgende analyser er foretaget med.



Figur 2.1: Principdiagram over EnergyPLAN-modellens energisystem

Som en del af projektet er CAES-anlæg som komponent blevet implementeret i EnergyPLAN-modellen på følgende måde:

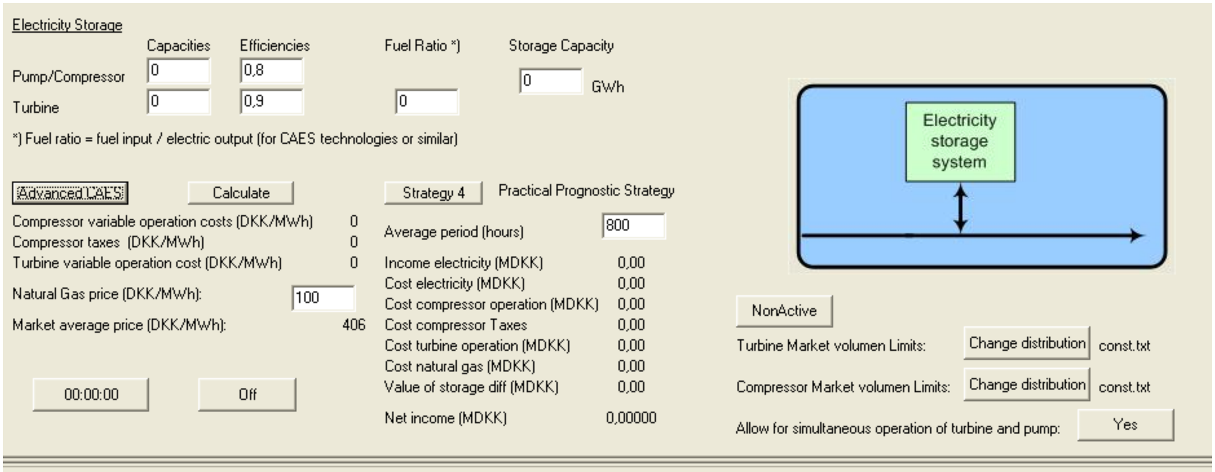
Efter samråd med DTU omfatter den tekniske beskrivelse turbine, kompressor og lagerkapaciteter samt turbine- og kompressoreffektivitet. Der regnes ikke med noget tab i lageret. Et eventuelt lagertab bør indregnes i effektiviteten. Turbinens brændselsforbrug angives som en ”Fuel ratio” defineret ved forholdet mellem brændselsforbruget og el-produktionen. Inputsiden er vist herunder:



Figur 2.2: Tekniske input til beskrivelse af CAES-anlæg i EnergyPLAN-modellen

I de systemtekniske analyser er reguleringen af CAES-anlægget meget simpel. Kompressoren forsøger at bruge så meget el-overløbsstrøm som muligt, og turbinen forsøger at erstatte el-produktion på kondensværker (ren kraftproduktion i modsætning til kraftvarme). I en markedsøkonomisk regulering indgår værket i et samspil med alle de øvrige komponenter, hvor hver især udbyder og efterspørger el på Nord Pool-markedet baseret på de kortsigtede marginale produktionsomkostninger inklusiv brændselsomkostninger og en eventuel CO2-kvote-betaling. En nærmere beskrivelse af disse reguleringer fremgår af dokumentationen.

Yderligere er der i forbindelse med dette projekt i EnergyPLAN-modellen implementeret en række muligheder for at beregne selskabsøkonomi på et enkelt CAES-anlæg og sammenligne denne med prisrækker på Nord Pool-markedet. Mulighederne aktiveres ved at trykke på ”Advanced CAES”-knappen, hvorved følgende skærmbillede fremkommer:



Figur 2.3: EnergyPLAN-skærmbillede for selskabsøkonomisk optimering af CAES-anlæg

I modellen kan vælges op til 6 forskellige reguleringsstrategier, som alle er udførligt beskrevet i appendiks C og D. Her skal kort fremhæves følgende strategier, som er anvendt i de efterfølgende analyser:

Strategi 6: Optimal indtjening
Denne strategi forudsætter fuldt kendskab til samtlige markedspriser time for time gennem et år. På den baggrund identificerer modellen den driftsform, som giver den optimale indtjening. Resultatet af modellen er blevet sammenlignet med tilsvarende simuleringer på hhv. EMD's EnergyPRO og DTU's dynamiske programmering. Med alle tre modeller kan man komme frem til samme optimum.

Strategi 4 og 5: Praktisk mulig indtjening
Disse to strategier tager hensyn til, at man i praksis ikke kender de kommende markedspriser. I stedet identificeres en strategi baseret på kendskab til de foregående 24-timers priser (strategi 5) og gennemsnitsprisen på de kommende 24-timers priser (strategi 4). Det sidste forudsætter en god prisprognose. De to reguleringsformer tenderer en simulering af, hvad man sandsynligvis i praksis vil kunne opnå. Og resultaterne i form af netto-indtjening ligger typisk knap 20% under de optimale.

I de efterfølgende analyser er der anvendt en gennemsnitsværdi af reguleringsstrategi 4 og 5, som udtryk for hvad der i praksis kan opnås. Denne indtjening er sammenlignet med det optimale i reguleringsstrategi 6.

3. Beregningsforudsætninger
(Defineret i samråd med DTU, DONG og Energinet.dk)

Der er regnet på to anlæg, et stort og et lille med et lager på hhv. 1478 og 692 MWh. De tekniske forudsætninger er defineret på baggrund af tidligere analyser hos hhv. DTU og DONG og fremgår af nedenstående tabel:

Technical Characteristics

		DTU	Dong	
Compressor	Capacity	216	89	MW
	Efficiency	0,6843	0,6478	-
Storage	Capacity	1478	691,8	MWh
Turbine	Capacity	360	150	MW
	Efficiency	2,4357	2,6019	-
	Fuel Ratio	1,1556	1,2200	-

Figur 3.1: Tekniske data for de to CAES-anlæg

De tilsvarende økonomiske parametre fremgår af nedenstående tabel. Bemærk, at der er indregnet en transmissionstarif på 4 og 15 DKK/MWh for henholdsvis køb og salg af elektricitet. Disse tal er oplyst af Energinet.dk (Henning Parbo). Hvis anlægget imidlertid betragtes som en systemoperatorkomponent vil der eventuelt ikke skulle opkræves nogen transmissionstarif. Derfor er der også gennemregnet enkelte situationer, hvor denne tarif sættes til nul.

Economic Parameters

		DTU		Dong Scenario		
Investment Cost	**Storage**	220	[2]	60	Mio kr.	[1]
	Surface Plant	1148	[2]	610	Mio kr.	[1]
Variable	**Compressor**	17			kr/MWh	[1]
Operation Costs	**Turbine**	20			kr/MWh	[1]
Transmission	**Consumption**	15			kr/MWh	[1]
Tariff	**Production**	4			kr/MWh	[1]
Annual Operational Costs		35		25	Mio.kr/MW	[1]
Lifetime		30			Years	
Interest		3,00%			%	
Op Reg Availability Payment		25.000			kr./(MW*Month)	[3]
Down Reg Availability Payment		8.000			kr./(MW*Month)	[3]

[1] PowerStore - Feasibility Study for a Danish Location - Objectives, Scop and Cost. Final Report v.1.0
[2] Elmegaard, Brian, Szameitat, Nicklas, and Brix, Wiebke. (2005), "Compressed air energy storage (CAES) -
[3] Henning Parbo

Figur 3.2: Økonomiske data for de to CAES-anlæg

Med hensyn til naturgaspriser og markedspriser på elektricitet er der taget udgangspunkt i dels historiske priser i perioden 2000 til 2006 og dels forventede fremtidige markedspriser anno 2015 og 2030.

De historiske priser er baseret på Nord Pool spotmarkedspriser for elektricitet samt, efter input fra DONG, tyske markedspriser for naturgas. I de historiske priser indgår ikke CO_2-betaling hverken i elpriserne eller i naturgaspriserne.

Mht. forventede fremtidige priser er der taget udgangspunkt i notatet "Forudsætninger for samfundsøkonomiske analyser på energiområdet" (Energistyrelsen, januar 2007). Ifølge dette notat forventes naturgasprisen inkl. transporttillæg til kraftværksniveau at være 40,2 DKK/GJ. Hertil kommer CO_2-betalingen på 150 DKK/ton, hvilket hæver den samlede pris med (56,7 kg CO_2 pr. GJ) 8,5 DKK/GJ til 48,7 DKK/GJ. Den gennemsnitlige Nord Pool-pris forventes på langt sigt (dvs. efter år 2016) at ligge på ca. 400 DKK/MWh inkl. effekten af en forventet CO_2-kvote pris på 150 DKK/ton.

For 2030 er gennemsnitsprisen 406 DKK/MWh. Denne gennemsnitspris er omsat til en timefordeling på følgende måde: CO_2-kvotebetalingen forudsættes at påvirke el-prisen med 60 DKK/MWh, som regnes konstant. Den øvrige del er forudsat efter samme fordeling som Nord Pool-priserne i 2005 (et typisk år). Desuden er der som følsomhed anvendt en prisfordeling svarende til de Tyske EEX-priser år 2005. Disse priser er ikke så influeret af vandkraft og svinger mere mellem dag og nat.

Fuel and electricity market prices

	CO2 Price	NGas	*Ngas + CO2*	*Nord Pool*	*EEX*	
Year	*[DKr/Ton]*	*[Kr/GJ]*	*[DKr/GJ]*	*[DKr/MWh]*	*[DKr/MWh]*	
2000		22,1		122	151	[1]
2001		28,87		177	179	[1]
2002		24,12		189	167	[1]
2003		25,34		250	219	[1]
2004		24,5		214	212	[1]
2005		33,38		277	342	[1]
2006		33,38		277	342	[1]
2030	150	40,2	48,70	406	406	[2]

[1] - Data Taken from energinet.dk and German Natural Gas Prices Excel file
[2] - Samfundsøkonomiske forudsætninger (Energistyrelsen, januar 2007)

Figur 3.3: Oversigt over forudsatte naturgaspriser og el-handelspriser

Med hensyn til regulerkraftmarkedet er der foretaget en beregning under forudsætning af, at CAES-anlægget kan opnå en fast betaling på 25.000 DKK/MW pr. måned for kapacitet, der stilles til rådighed for opregulering. Denne indtægt er indregnet ved at reservere en andel af turbinekapaciteten til dette formål. For nedregulering er der tilsvarende regnet med en pris på 8000 DKK/MW pr. måned. Disse tal er valgt på baggrund af en vurdering af de typiske fremtidige indtjeningsmuligheder foretaget af energinet.dk (Henning Parbo).

Som nævnt, er der indregnet en indfødningsafgift (transmissionstarif) på hhv. 4 og 15 DKK/MWh. Herudover vil køb af elektricitet til kompressoren i princippet være omfattet af en afgift sammensat af en elafgift på 650 DKK/MWh plus PSO-tariffen. Da denne imidlertid har stor betydning for den samlede økonomi, har det været på tale om CAES-anlægget skulle fritages for denne afgift, og derfor er det her valgt at gennemføre kalkulationer både med og uden denne tarif. Med hensyn til fastlæggelse af tariffens størrelse er der taget udgangspunkt i de konkrete historiske tariffer, jf. nedenstående tabel fra energinet.dk's hjemmeside:

PSO-tariffer

PSO-tarif	Øre/kWh		
	Lavlast	Højlast	Spidslast
Tarif pr. 1. januar 2000	2,8	2,8	2,8
Tarif pr. 1. januar 2001	4,2	4,2	4,2
Tarif pr. 1. juni 2001	3,6	3,6	3,6
Tarif pr. 1. september 2001	2,6	2,6	2,6
Tarif pr. 1. januar 2002	2,3	2,3	2,3
Tarif pr. 1. januar 2003	3,0	3,0	3,0
Tarif pr. 1. april 2003	2,2	2,2	2,2
Tarif pr. 1. januar 2004	4,0	4,0	4,0
Tarif pr. 1. april 2004	2,9	2,9	2,9
Tarif pr. 1. januar 2005	11,7	11,7	11,7
Tarif pr. 1. april 2005	15,7	15,7	15,7
Tarif pr. 1. juli 2005	9,8	9,8	9,8
Tarif pr. 1. oktober 2005	6,9	6,9	6,9
Tarif pr. 1. januar 2006	4,8	4,8	4,8

Figur 3.4: PSO-tarif downloaded fra Energinet.dk´s hjemmeside

Selve tariffen er bestemt af støttebehovet til vindkraft og decentral kraftvarme og er derfor en funktion af markedsprisen - jo højere spotmarkedspris, jo lavere PSO-afgift. Desuden er støtteordningerne tidsmæssigt begrænset. På den baggrund er PSO-afgiften sat til lig nul for år 2030, men denne prisfastsættelse skal naturligvis tages med et stort forbehold.

De resulterende afgifter fremgår af nedenstående tabel

DKK/MWh	Ved salg	Ved Køb			
År	Transmission	Transmission	PSO	Elafgift	Total
2000	4	15	28	650	693
2001	4	15	37	650	702
2002	4	15	23	650	688
2003	4	15	24	650	689
2004	4	15	32	650	697
2005	4	15	110	650	775
2006	4	15	48	650	713
2030	4	15	0	650	665

Figur 3.5: Sammenregning af el-afgifter

I beregningerne i EnergyPLAN er ovennævnte afgifter medtaget som en forøgelse af de variable driftsomkostninger, således at der er regnet med følgende samlede variable drifts- og afgiftsomkostninger.

DKK/MWh	Turbine (Salg)	Kompressor (Køb)	
År	I begge tilfælde	Alt.1: Uden afgifter	Alt.2: Med afgifter
2000	24	32	710
2001	24	32	719
2002	24	32	705
2003	24	32	706
2004	24	32	714
2005	24	32	792
2006	24	32	730
2030	24	32	682

Figur 3.6: Anvendte variable driftsomkostninger inkl. afgifter i selskabsøkonomiske beregninger

I de systemtekniske analyser er CAES blevet sammenlignet med en række andre typer af el-lagring og reguleringsmetoder i forbindelse med el-overløb i fremtidens el-system. Denne sammenligning er lavet ved at definere en række andre teknologier med samme faste omkostninger som CAES-anlægget.

Med en levetid på 30 år og en realrente på 3% har DTU fastsat CAES-anlæggets faste omkostninger på 105 million kr. pr. år. Med udgangspunkt i Appendiks E (uddrag af artiklen ”Relocation Technologies for Integration of Fluctuating Renewable Energy Sources”, Mathiesen og Lund 2007) er der identificeret følgende relevante teknologier, som er medtaget i vurderingen:

De viste teknologier er her skaleret op og ned, så de ender på samme faste omkostninger (afskrivninger og faste drifts- og vedligeholdelsesomkostninger) som CAES-anlægget. Herefter er de variable indtægter og udgifter udregnet, hvorved der kan foretages en økonomisk sammenligning af, hvor man som samfund får mest for pengene.

Teknologi	Beskrivelse	Faste omkostninger (drift og investering ved realrenten 3%)
CAES	360 MW turbine, 216 MW kompressor, 1,478 GWh lager, Levetid 30 år	105 mio.kr./år
EP Elpatron	1300 MW elpatron, 1 mio.kr./MW Levetid 20 år Driftsudgift 1-2%	105 mio.kr./år
VP Store varmepumper i kraftvarme-systemer	85 MW varmepumpe (inkl. termisk lager) 16 mio.kr./MWe COP = 3,5 Levetid 20 år Driftsudgifter 1%	105 mio.kr./år
ELC Elektrolyse til at erstatte naturgas i eksisterende kraftvarmesystemer	535 MW elektrolyse 1,9 mio.kr./MWe Levetid 20 år Driftsudgifter 3% 360 GWh H2-lager 0,4 mio.kr./GWh Levetid 25 år Driftsudgifter 0% Samlet effektivitet = 72% H2 og 10% fjv.	105 mio.kr./år
H2 Elektrolyse til lager til brint brændselscelle	180 MW elektrolyse (som ovenfor) 120 GWh H2-lager (som overfor) 90 MW brændselscelle 6 mio.kr./MWe Levetid 20 år Driftsudgifter 6% Elektrolyse og lager : 72% Brændselscelle : 56% Samlet effektivitet: 40%	105 mio.kr./år

Figur 3.7: Oversigt over alternative el-regulerings- og lagringsteknologier

4. Samfundsøkonomiske Systemanalyser

Der er foretaget en række omfattende systemanalyser af et CAES-anlægs evne til at forbedre det samlede danske energisystem. Analyser, forudsætninger og resultater er beskrevet i artiklen: *Energy System Analysis of CAES Technologies in the Danish Energy System with High Penetration of Fluctuating Renewable Energy Sources* (Appendiks A).

Formålet med disse analyser er at finde ud af, hvor meget et CAES-anlæg kan forbedre systemeffektiviteten i det danske energisystem (nedbringe det samlede brændselsforbrug) ved at lagre el-overløb og anvende dette til at erstatte elproduktion på kondensværker. Behovet for en sådan ydelse er i sagens natur meget afhængig af, hvor stort el-overløbet er, og derfor er analyserne foretaget for et spektrum fra de nuværende 20% vind og helt op til 100% vind (målt ift. elforbruget).

Analyserne viser, at CAES-anlægget kun har meget begrænset indflydelse på den samlede systemeffektivitet. CAES-anlægget begrænses af to forhold. Det ene er, at der på årsbasis skal være både en vis mængde el-overløb og en vis mængde kondensproduktion, for at CAES-anlægget kan komme i spil. Det andet er anlæggets kapaciteter, som viser sig at være meget begrænsende ift. såvel energimængden som effekten af de mængder el, der skal flyttes.

Der er efterfølgende foretaget en række supplerende beregninger og fremstillet en række figurer, som vises i det følgende med henblik på at illustrere konsekvenserne af de nævnte begrænsninger.

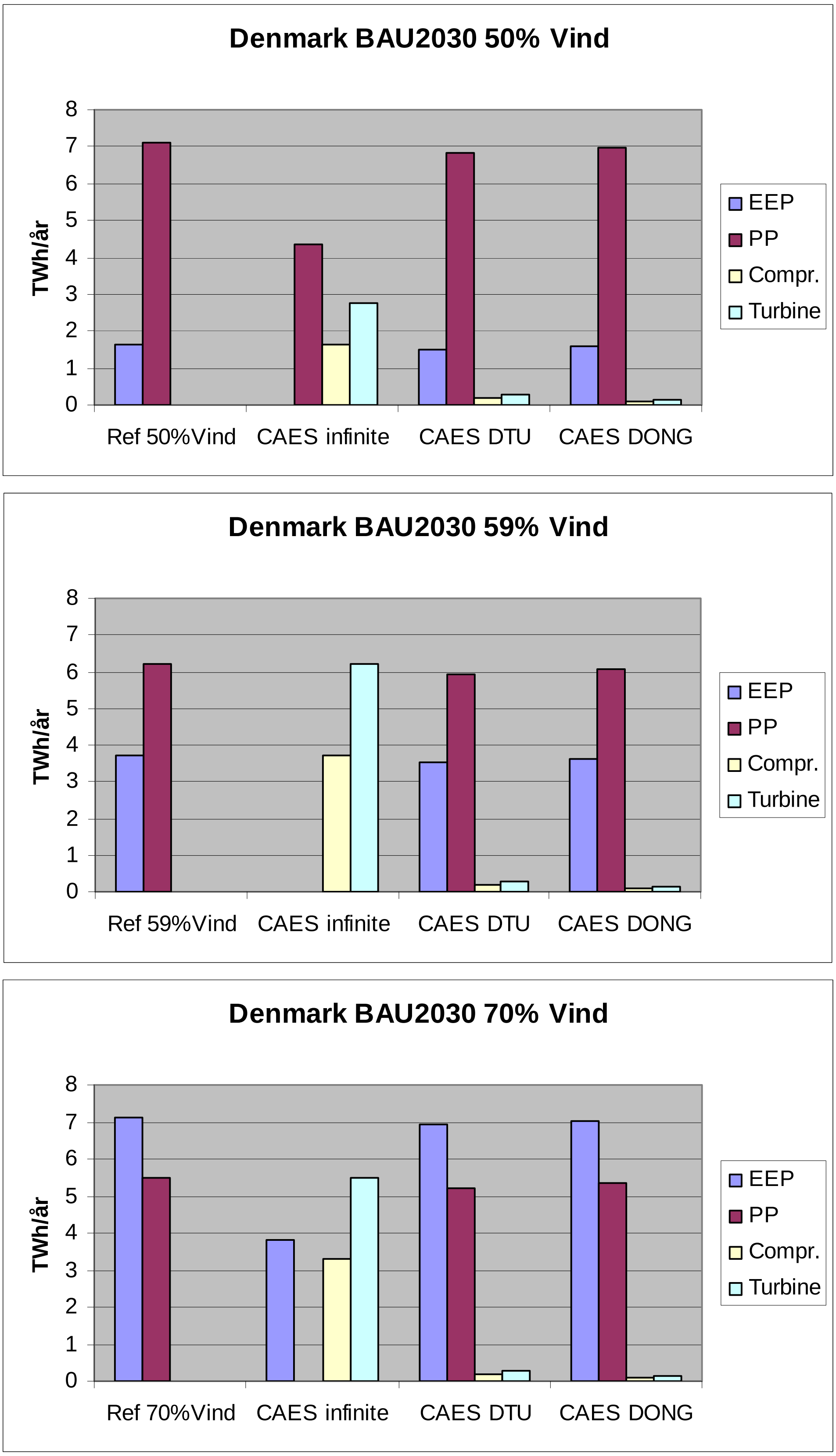
Figur 4.1 sammenligner et dansk referenceenergisystem hhv. med og uden et CAES-anlæg. Som referencesystem er valgt Energistyrelsens "Business As Usual"-reference år 2030, men resultaterne vil være de samme også for det nuværende energisystem.

I figuren er vist omfanget af el-overløb og elproduktion på kondensværker i tre situationer med hhv. 50%, 59% og 70% vindkraft.

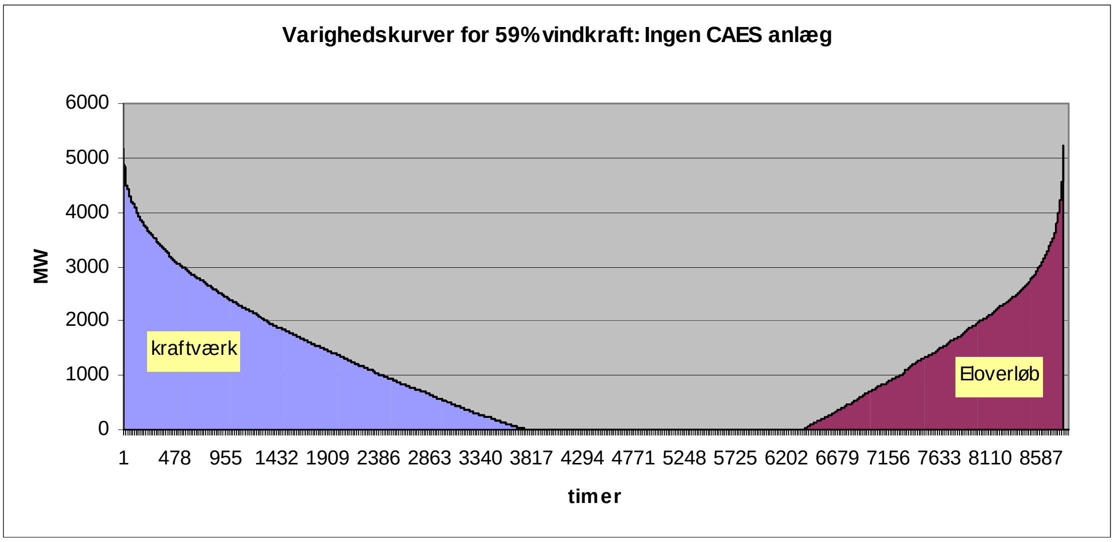
Som det ses, stiger el-overløbet med et stigende vindkraft-input, mens elproduktionen på kondensværkerne falder.

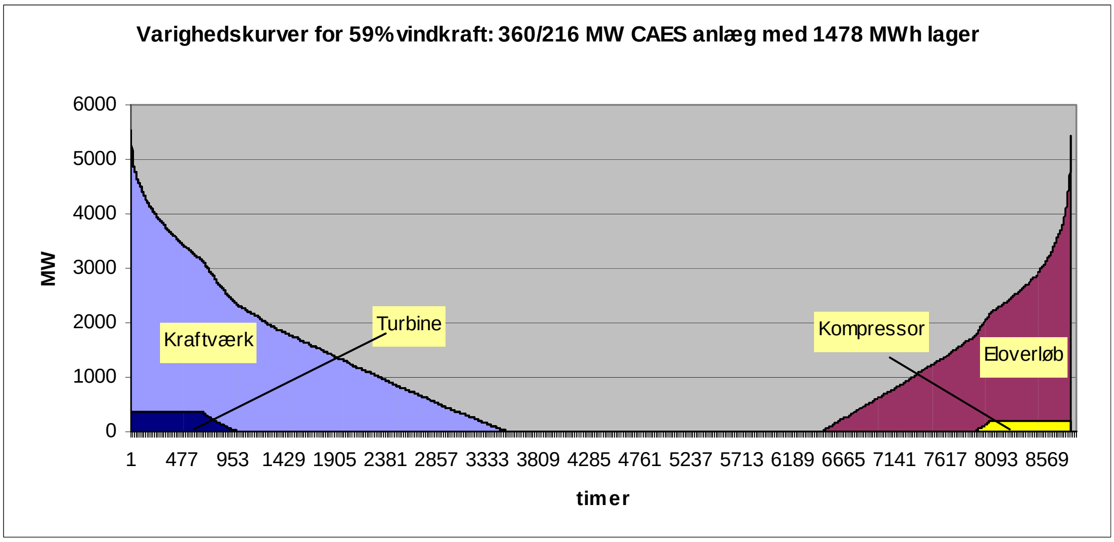
Set fra CAES-anlæggets side opnås det optimale forhold mellem el-overløb og kondensdrift i en situation med 59% vindkraft. I denne situation svarer forholdet netop til forskellen mellem kompressorens forbrug og turbinens produktion, når lageret skal tømmes.

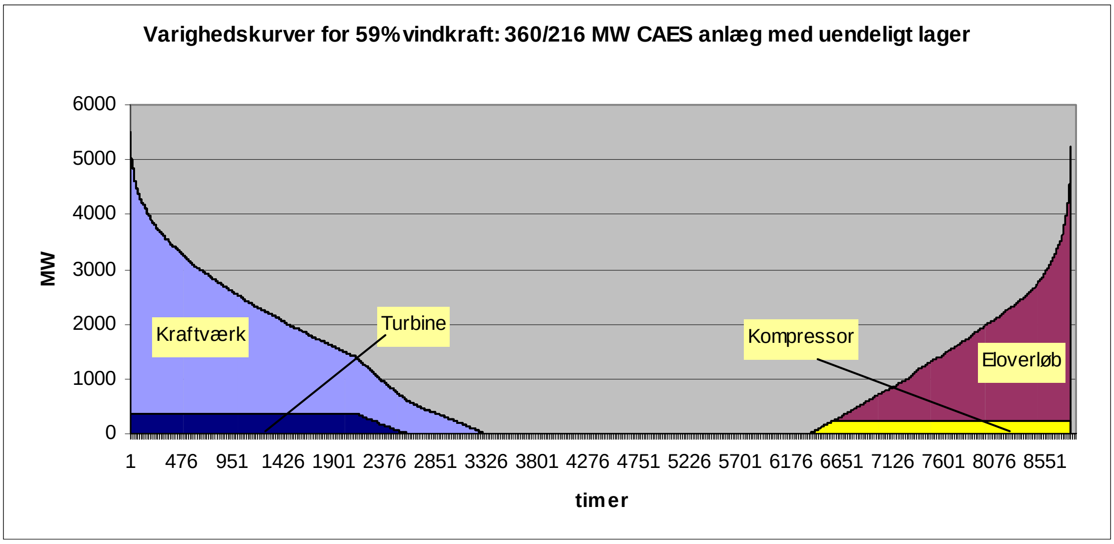
Figur 4.1 viser tre forskellige CAES-anlægs evne til at nedbringe el-overløb og kondensdrift. Det første CAES-anlæg er et anlæg med uendeligt store kapaciteter på såvel lager som turbine og kompressor. Et sådant anlæg vil i en situation med 59% vindkraft kunne fjerne hele el-overløbet og hele kondensdriften. Men ved mindre vindinput vil selv et uendeligt stort CAES-anlæg være begrænset af mængden af el-overløb. I situationen med 50% vindkraft vil anlægget således nok kunne fjerne el-overløbet, men ikke undgå kondensdrift. Omvendt i situationer med højere vindinput vil CAES-anlægget nok kunne fjerne kondensdriften, men ikke kunne udnytte hele el-overløbet.



Figur 4.1: Tre forskellige CAES-anlægs evne til at mindske el-overløb og kondensdrift i energisystemet (DK anno 2030) med tre forskellige vindkraft-input.







Figur 4.2: Varighedskurver til illustration af CAES-anlæggets tidsmæssige og kapacitetsmæssige sammenfald med el-overløb i kraftværksproduktion

Figur 4.1 viser også resultaterne af analyserne af de to konkrete CAES-anlæg: DTU-anlægget med en 360 MW turbine og DONG-anlægget med en 150 MW turbine. Som det ses, har disse anlæg marginal indflydelse på el-overløbet samt kondensproduktionen i det samlede energisystem. Dette skyldes to forhold.

Det ene forhold er begrænsningen i turbine- og kompressorkapaciteterne. Det andet forhold er begrænsningen i lageret. Betydningen af disse begrænsninger er vist i figur 4.2. I det øverste diagram ses varighedskurverne af hhv. kondensproduktionen og el-overløbet. Som det ses, er effekterne i store dele af tiden meget større end turbine- og kompressorkapaciteterne på hhv. 216 og 360 MW.

Det midterste diagram illustrerer hvilken del af hhv. el-overløbet og kraftværksproduktionen det er muligt for CAES-anlægget at overtage. Horisontalt er CAES-anlægget begrænset af turbine og kompressor, og vertikalt af lagerstørrelsen.

I det nederste diagram er lagerbegrænsningen fjernet. Selv i denne situation er CAES-anlæggets indflydelse dog begrænset.

Selvom CAES-anlæggets indflydelse på el-overløb og kondensproduktion er marginal, kan økonomien imidlertid godt være positiv.

Derfor er økonomien analyseret for tre forskellige brændselsprisniveauer og tre forskellige værdier af el-overløbet.

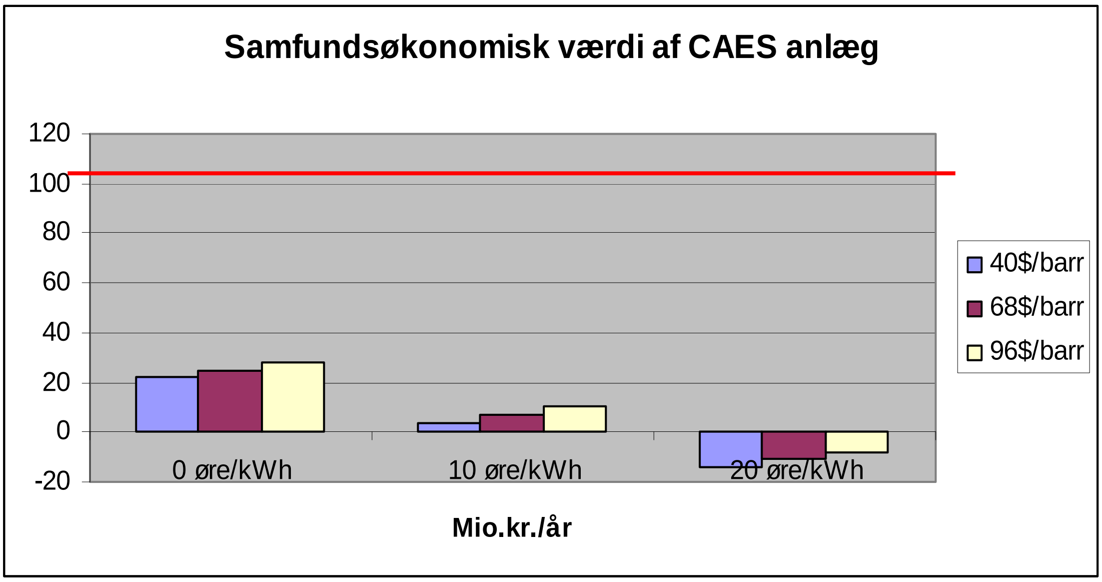
Med hensyn til den samfundsøkonomiske værdi af brændselsbesparelserne i det samlede system er der taget udgangspunkt i Energistyrelsens forudsætningsskrivelse. Heri angives en række sammenhængende brændselspriser inkl. håndteringsomkostninger til forskellige typer af energianlæg. Der er taget udgangspunkt i prisniveauet fra 2006, som kan beskrives ved en råoliepris på 68 $/tønde. I forhold hertil er der defineret et brændselsprissæt med lave priser svarende til en råoliepris på 40 $/tønde og et med høje priser svarende til 96 $/tønde.

Med hensyn til værdien af el-overløbet er der regnet på hhv. 0, 10 og 20 øre/kWh.

Resultatet af analysen er vist i figur 4.3, hvor de variable netto-indtægter er sammenlignet med de faste omkostninger, som for DTU-anlægget med en levetid på 30 år og en rente på 3% er opgjort til 105 millioner kr./år.

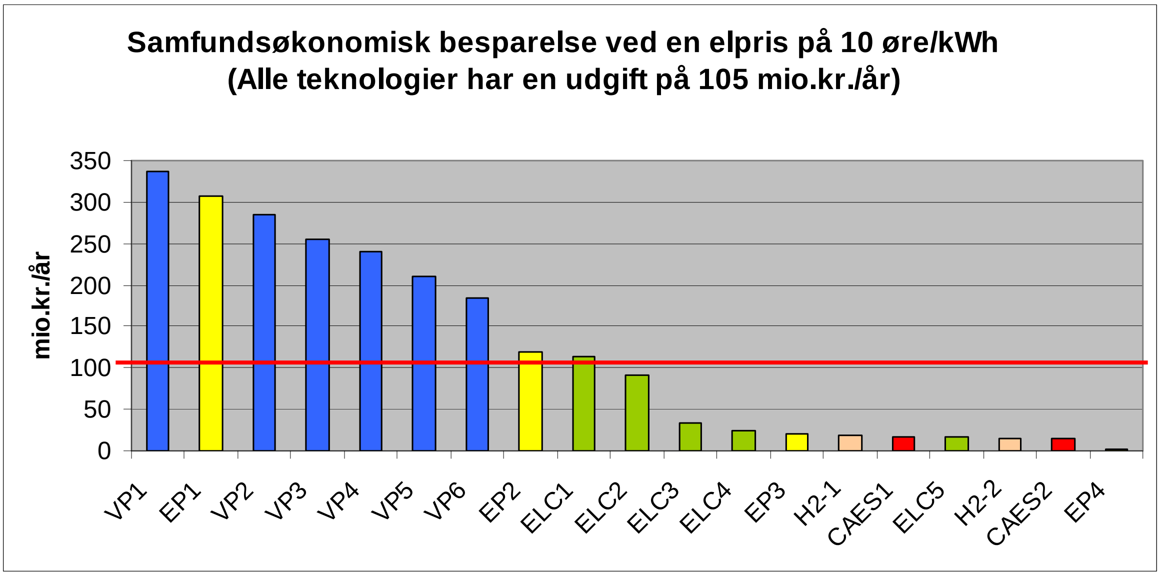
Som det ses, er resultatet ikke særligt influeret af brændselsprisniveauet. Det skyldes dels, at brændselsbesparelsen blandt andet er kul, som ikke varierer så meget som olieprisen i Energistyrelses forudsætningsskrivelse, og dels at CAES-anlægget selv bruger naturgas.

Derimod er økonomien meget afhængig af værdien af el-overløbet, hvis det alternativt afsættes på NordPool-markedet. Selv med en pris på 0 øre/kWh ligger CAES-anlæggets variable nettoindtægter kun lidt over 20 millioner kr./år, hvilket er langt fra at kunne betale de faste omkostninger på 105 millioner kr./år, vist i figuren med en rød linie.



Figur 4.3: Årlige variable samfundsøkonomiske netto-indtægter sammenlignet med årlige faste omkostninger (vist med rødt foroven).

Der er herefter foretaget en økonomisk sammenligning med en række andre teknologier, som vist i figur 4.4:



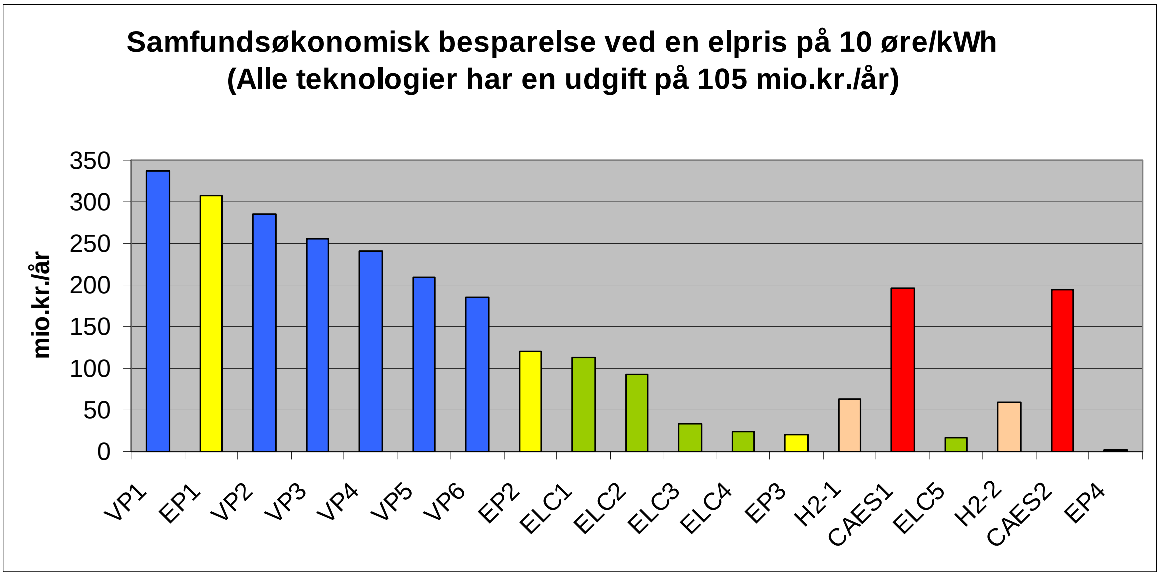
Figur 4.4: Samfundsøkonomisk besparelse for en række alternative teknologier.
VP = 85 MWe varmepumper på kraftvarmeværker
EP = 1300 MWe elpatron i fjernvarmeværker
ELC = 535 MWe elektrolyseanlæg, hvor brint erstatter naturgas i kraftvarmeværker
H2 = 180 MWe elektrolyse 90 MWe brændselsceller med H2-lager

Figur 4.4 er lavet ved at sammenligne de samfundsøkonomiske indtægter (værdi af brændselsbesparelse og variable drifts- og vedligeholdelsesomkostninger) for en række udbygninger, der alle har samme faste årlige omkostninger på 105 mio.kr./år. For varmepumper i fjernvarmesystemer (VP) er der tale om 85 MWe. VP1 gælder de første 85 MWe, VP2 de næste 85 MWe, osv.

Sammenligningen er fortaget for brændselsprisniveauet 68$/tønde og el-overløbsprisen 10 øre/kWh. Billedet ændrer sig imidlertid ikke meget for de øvrige forudsætninger, bortset fra el-patronen, der er meget følsom over for elprisen.

Som det ses, er der endog meget stor forskel på værdien af disse investeringsmuligheder, og CAES1 og CAES2 kommer meget langt nede i rækken.

Det skal understreges, at ovennævnte analyse alene omfatter de enkelte investeringers evne til at nyttiggøre el-overløb og forbedre den samlede brændselseffektivitet. På et væsentligt punkt er teknologierne ikke helt sammenlignelige. CAES og H2 investeringerne omfatter en el-kapacitet på hhv. 360 og 90 MWe. Kan denne kapacitet omsættes til en sparet kraftværksudbyning, og værdisættes denne f.eks. til 8 mio.kr. pr. MW, 30 år og 3% plus faste drifts- og vedligeholdsudgifter på 1-2% svarende til 0,5 mio.kr./år pr. MW, ændres billedet til figur 4.5:

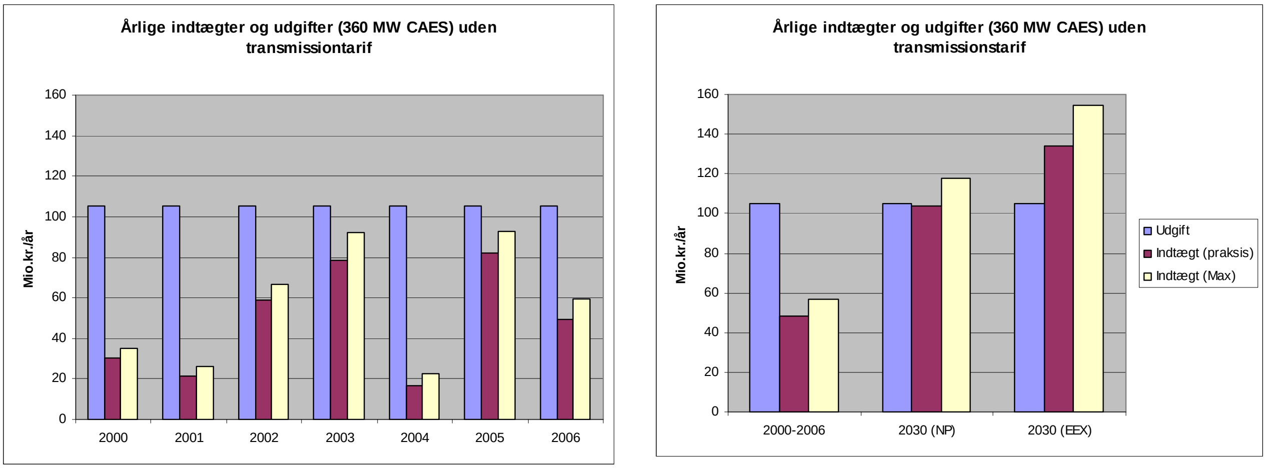


Figur 4.5: Samme som 4.4 men med indregning af eventuel værdi af sparet kraftværk.

Konklusionen er, at set isoleret ”i forbindelse med el-overløb i fremtidens el-system”, er CAES-anlæggets systemmæssige og samfundsøkonomiske værdi negativ. Og der findes en række alternativer, der udviser væsentligt bedre og mere positiv værdi. Kan CAES-anlægget imidlertid samtidigt spare et tilsvarende kraftværk, er der potentiale for en positiv økonomi.

5. Selskabsøkonomiske analyser af enkeltanlæg

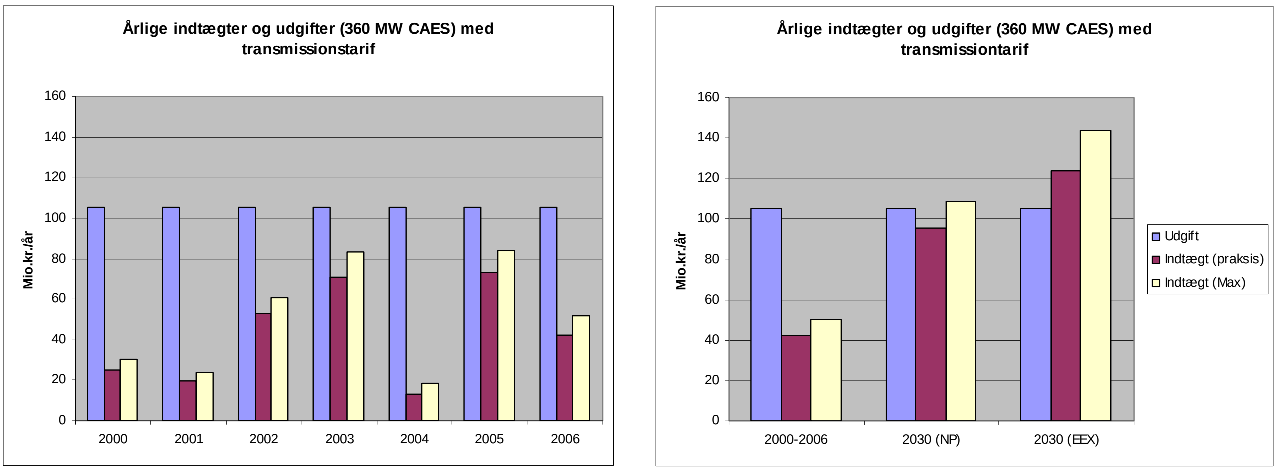
Der er først foretaget en selskabsøkonomisk analyse af DTU-anlægget under de i afsnit 3 nævnte forudsætninger, dog uden betaling af hverken transmissionsafgift, elafgift eller PSO-afgift. Analysen omfatter dels den historiske periode fra 2000 til 2006 og dels år 2030 med Energistyrelsens forventninger til el- og naturgas-priser for hhv. en Nord Pool og en EEX-prisdistribution. Resultatet fremgår af figur 5.1 samt af den tilhørende resultattabel (se bilag bagerst i rapporten).



Figur 5.1: Årlige indtægter og udgifter for 360 MW anlæg på spotmarkedet uden nogen afgifter

De blå søjler viser den årlige udgift til afskrivninger og faste driftsomkostninger (under forudsætning af en levetid på 30 år og en realrente på 3%). Den gule søjle viser den maximalt mulige netto-indtjening (indtægter minus variable omkostninger), og den røde søjle viser den forventede netto-indtjening i praksis under forudsætning af en god prisprognose inden for et døgn. (Sammenvejning af reguleringsstrategi 4 og 5 i EnergyPLAN-modellen).

I figur 5.2 er den tilsvarende figur vist, hvis transmissionstarifferne indregnes.

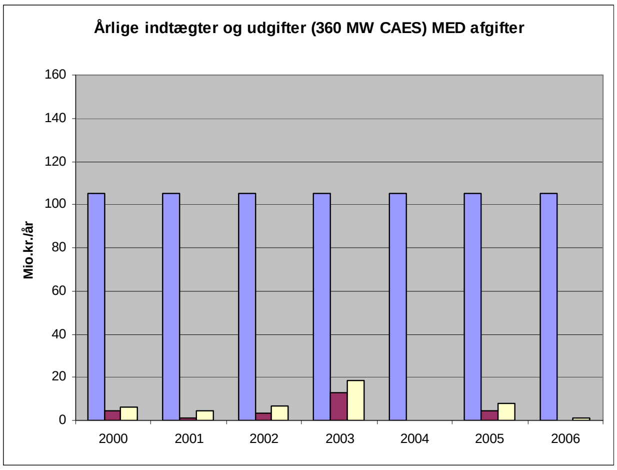


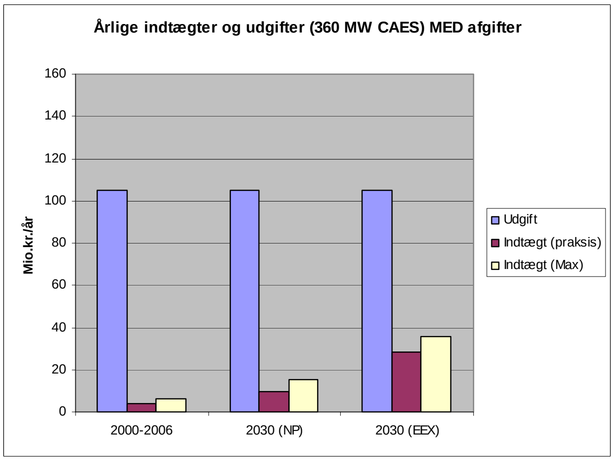
Figur 5.2: Årlige indtægter og udgifter for 360 MW anlæg på spotmarkedet inkl. transmissionsafgifter

Som det ses af figurerne, er indtjeningen meget svingende. I de 7 år, der foreligger Nord Pool-spotmarkedspriser for, svinger den således mellem 12 og 70 millioner om året. Og i alle årene er der underskud. I gennemsnit ligger de variable nettoindtægter på ca. 40 millioner kr./år mod faste udgifter på 105 millioner kr./år. De store svingninger skyldes dels variationer i Nord Pool-markedsprisen fra år til år og dels variationer i naturgasprisen. Da disse to afgørende faktorer ikke følges ad, er det især i årene med relativt høje elpriser og lave naturgaspriser, der er en relativ god indtjening.

For år 2030 ser økonomien bedre ud. Det skyldes først og fremmest, at Energistyrelsens forventninger kombinerer relativt høje spotmarkedspriser for el (406 DKK/MWh i gennemsnit) med relativt afdæmpede forventninger til stigning i naturgasprisen. Selv med disse forventninger er anlægget dog næppe rentabelt med Nord Pool-prisvariationer. Derimod viser analysen, at CAES-anlægget med EEX-prisvariationer (større og hyppigere prisforskelle) bliver rentabelt.

Hvis CAES-anlægget bliver pålagt at betale el-afgift, ser resultaterne ud som vist i figur 5.3. Som det fremgår, er økonomien helt umulig i denne situation. Det er altså en klar forudsætning for overhovedet at overveje muligheden, at anlægget fritages for el-afgifter og PSO-afgifter.



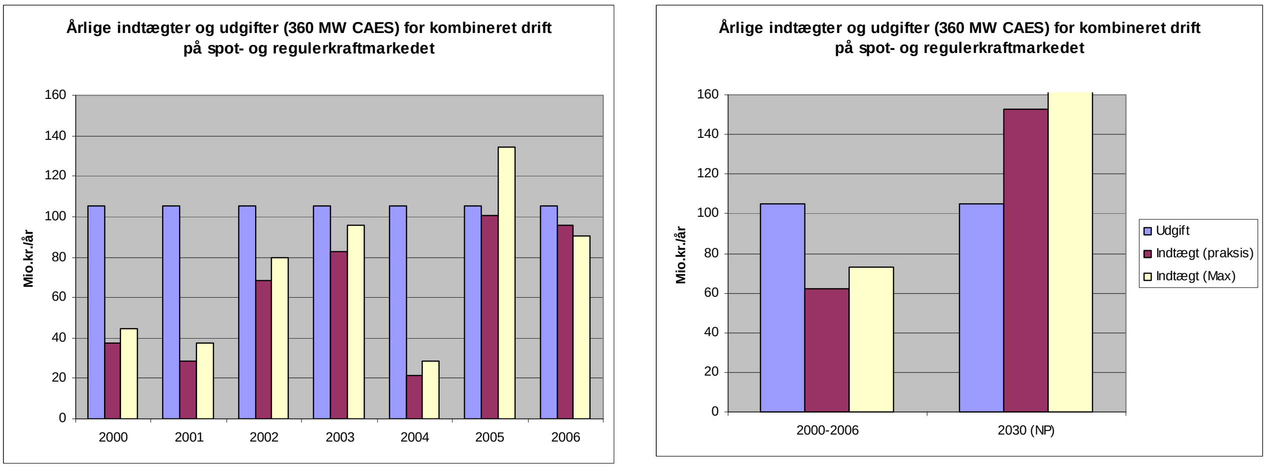


Figur 5.3: Årlige indtægter og udgifter for 360 MW anlæg på spotmarkedet <u>med</u> elafgifter

De ovenstående resultater bekræfter de tidligere analyser dels i, at afgiftsfritagelsen er essentiel, og dels i at et CAES-anlæg næppe er rentabelt alene på spotmarkedet. På den baggrund er der foretaget en række analyser, hvor CAES-anlægget byder ind på såvel spotmarkedet som regulerkraftmarkedet.

Der er indledningsvist foretaget en analyse, hvor dele af turbinen simpelthen reserveres til opregulering, hvilket honoreres med et fast beløb på 25.000 DKK/MW pr. måned, og den resterende turbinekapacitet optimeres på spotmarkedet, som vist ovenfor. En sådan analyse fører til det resultat, at den maksimale indtjening opnås i det tilfælde, hvor hele turbinen er reserveret til opregulering. Her opnås der en indtjening på 108 millioner DKK/år, hvilket lige akkurat modsvarer de faste omkostninger på 105 millioner DKK/år.

Herefter er der foretaget en række analyser, hvor anlægget forudsættes at optimere sin drift såvel på spotmarkedet som regulerkraftmarkedet time for time. Disse analyser er baseret på samme historiske spotmarkedspriser som ovenfor, blot suppleret med tillæg og fradrag fra regulerkraftmarkedet. Resultatet fremgår af figur 5.4:



Figur 5.4: Årlige indtægter og udgifter for 360 MW anlæg såvel på spotmarked som regulerkraftmarked

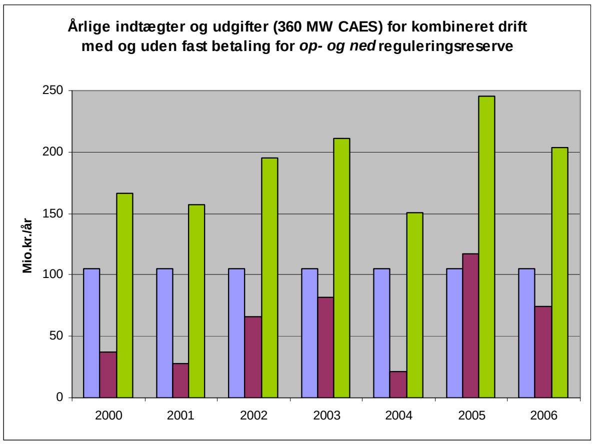
I figur 5.4 er ikke medtaget faste indtægter fra regulerkraft, idet det med ovennævnte driftsform ikke sikres, at turbinen altid er til rådighed. I visse driftssituationer vil turbinen være budt ind på spotmarkedet og vil således muligvis ikke være til rådighed til opregulering i den pågældende time.

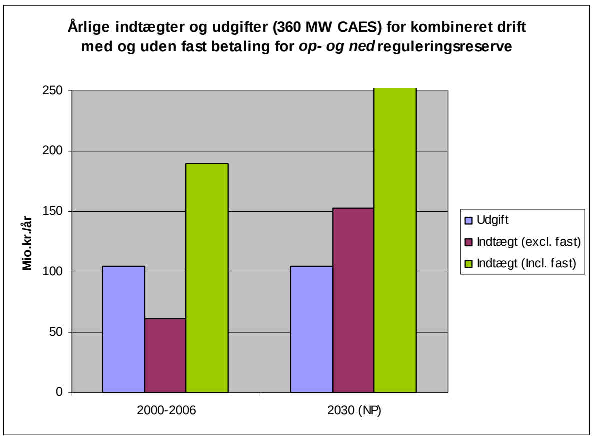
Som det ses ved at sammenligne figur 5.2 og 5.4, forbedres økonomien en smule. For den historiske periode 2000 til 2006 forbedres de gennemsnitlige netto-indtægter fra ca. 40 til 50 million DKK/år. Der er dog fortsat langt op til at kunne dække de faste omkostninger på 105 millioner DKK/år. Og det skal samtidig bemærkes, at der i ovennævnte indtægter i visse tilfælde kan være medregnet indtægter fra regulerkraftmarkedet, som går ud over markedsvolumen.

Konklusionen er således, at der skal genereres indtægter fra såvel fast betaling fra regulerkraft som fra handel på enten et eller begge markeder, spot- såvel regulerkraft.

I figur 5.5 vises potentialet for sådanne indtægter.

Som det ses, bliver CAES-anlægget økonomisk interessant i denne situation. Det forudsætter imidlertid, at anlægget er i stand til at optimere sin indtjening på såvel spotmarkedet som regulerkraftmarkedet, samtidigt med at anlægget står til rådighed for opregulering. Dette vil ikke kunne lade sig gøre i praksis, og figuren skal således betragtes som en illustration af potentialet.

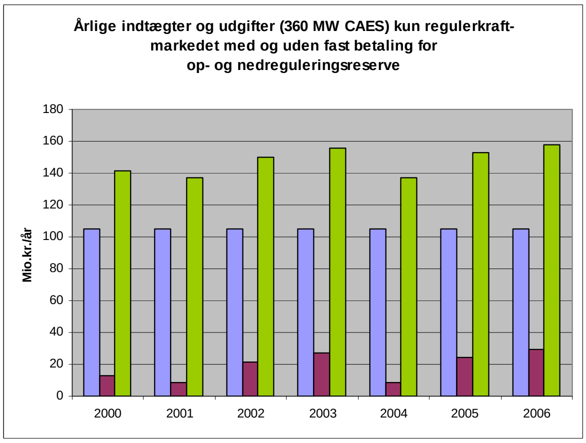


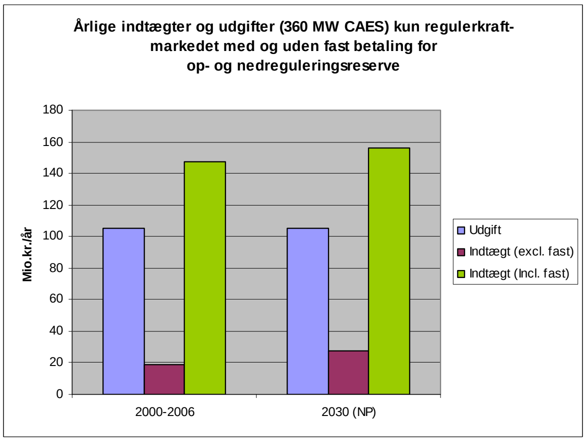


Figur 5.5: Årlige indtægter og udgifter for 360 MW anlæg såvel på spotmarked som regulerkraftmarked hhv. med og uden faste indtægter for op- og nedreguleringseffekt.

Som et bud på hvad der i praksis kan lade sig gøre, er der foretaget en beregning, hvor CAES-anlægget alene opererer på regulerkraftmarkedet inden for den markedsvolumen, der historisk set har været gældende i de anvendte år, og samtidig opnår den faste betaling for såvel opregulering som nedregulering. Når anlægget alene opererer på regulerkraftmarkedet sikres det, at anlægget ikke kommer i en situation, hvor det ikke kan producere, fordi det allerede er budt ind på spotmarkedet.

Figur 5.6 viser resultatet af analysen. Som det ses, er anlægget økonomisk rentabelt i denne situation med en gennemsnitindtægt i årene 2000-2006 på 148 mio.kr./år.



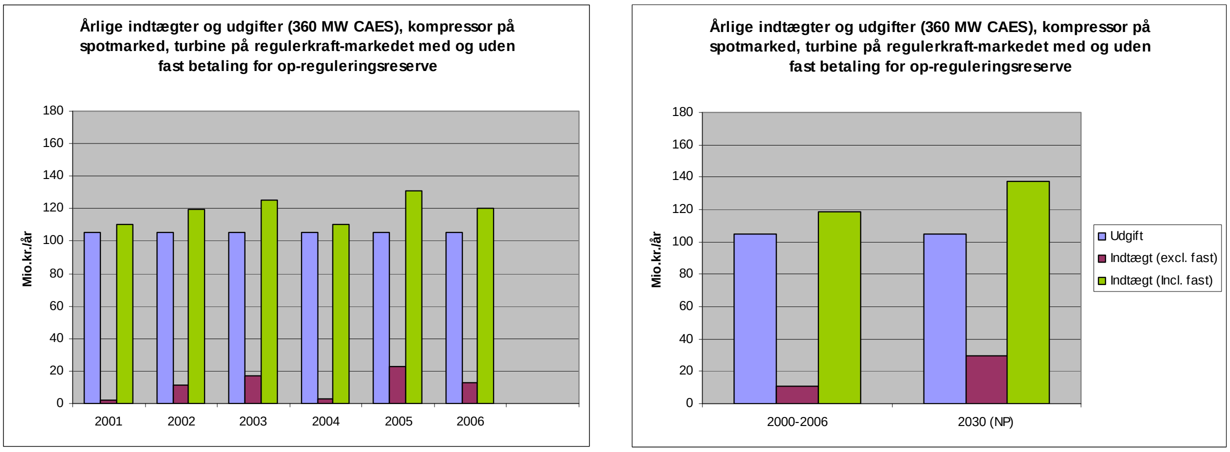


Figur 5.6: Årlige indtægter og udgifter for 360 MW anlæg alene drevet på regulerkraftmarkedet hhv. med og uden faste indtægter for op og ned-reguleringseffekt.

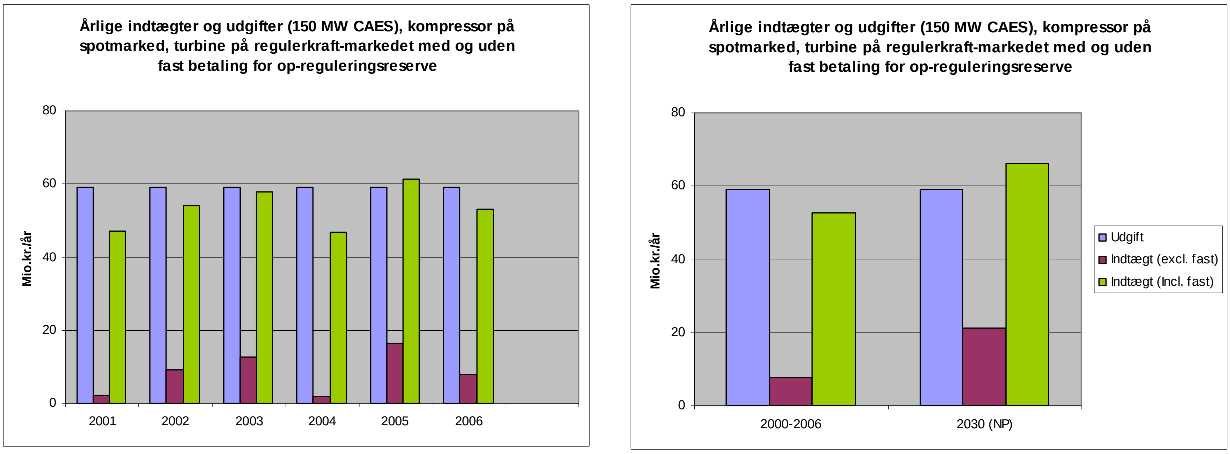
Problemet ved driftsformen i figur 5.6 er imidlertid, at anlægget vil kunne komme i den situation, at lageret er fuldt, og det bliver kaldt til nedregulering, eller det kan komme i den situation, at lageret er tomt, og det bliver kaldt til opregulering. I begge situationer vil anlægget ikke kunne opfylde sine forpligtigelser i forhold til at opnå fast betaling.

Dette problem vil kunne undgås ved følgende kombination: Turbinen bydes ind på regulerkraftmarkedet og opnår fuld fast betaling. Turbinen drives udelukkende på regulerkraftmarkedet, hvorved det sikres, at man aldrig kommer i den situation, at turbinen ikke kan deltage på regulerkraftmarkedet, fordi den allerede er budt ind på spotmarkedet. Kompressoren derimod bydes alene ind på spotmarkedet, så det sikres, at lageret aldrig er helt tomt. Resultatet af en sådan driftsform er vist i figur 5.7. I denne situation vil der kunne opnås en gennemsnitlig årlig indtægt på 125 mio.kr./år i årene 2000-2006.

I figur 5.8 er den tilsvarende analyse vist for det mindre anlæg på 150 MW turbine. Dette anlæg vil ikke kunne opnå overskud.



Figur 5.7: Årlige indtægter og udgifter for 360 MW anlæg hvor kompressoren bydes ind på spotmarkedet, mens turbinen bydes ind på regulerkraftmarkedet hhv. med og uden faste indtægter for 360 MW opreguleringseffekt.



Figur 5.8: Årlige indtægter og udgifter for 150 MW anlæg hvor kompressoren bydes ind på spotmarkedet, mens turbinen bydes ind på regulerkraftmarkedet hhv. med og uden faste indtægter for 150 MW opreguleringseffekt.

Hovedkonklusionen af ovennævnte analyser er, at det er helt afgørende for CAES-anlæggets selskabsøkonomi, at det opnår fuld fast betaling for opregulering. Herudover skal der som minimum tjenes penge på regulerkraftmarkedet og også gerne på en kombination af spot- og regulerkraftmarkederne. Analyserne viser, at over den historiske periode fra 2000 til 2006 ville det have været muligt at opnå gennemsnitlige indtægter på årligt 125 mio.kr. ved at drive turbinen på regulerkraftmarkedet og kompressoren på spotmarkedet. Og potentialet for udnyttelse af begge markeder ligger på 190 mio. DKK/år. Disse indtægter skal sammenholdes med en årlig fast udgift på 105 mio. DKK/år for en levetid på 30 på og en realrente på 3%. De

125 mio.kr. er et beløb, der ville kunne realiseres, mens de 190 mio.kr./år derimod er et maksimum, som ikke vil kunne realiseres i praksis, idet det skal sikres at turbinen hele tiden er til rådighed for regulerkraftmarkedet. Det anbefales derfor, at EnergyPRO-modellen anvendes med henblik på at vurdere, hvor langt man i praksis vil kunne komme i nærheden af denne indtægt uden at sætte den faste betaling over styr.

Bilag: Resultattabeller.

Tabel 1: Results for DTU plant (360 MW turbine) NOT including transmission tarifs

Year	Main price input				Net profit before fixed costs			Fixed Costs		Resulting net profit		
	Natural	Variable Opr. Costs		Average	Reg 4	Reg 5	Reg 6	O&M	Invest	Reg 4	Reg 5	Reg 6
	Gas	Turbine	Compress.	El-price								
	DKK/MWh				MDKK	MDKK	MDKK	MDKK	MDKK	MDKK	MDKK	MDKK
2000	79,56	20	17	122	30	31	35	35	70	-75	-74	-70
2001	103,93	20	17	177	22	21	26	35	70	-83	-84	-79
2002	86,83	20	17	189	60	57	67	35	70	-45	-48	-38
2003	91,22	20	17	250	82	75	92	35	70	-23	-30	-13
2004	88,20	20	17	214	19	14	23	35	70	-86	-91	-82
2005	120,17	20	17	277	83	82	93	35	70	-22	-23	-12
2006	153,72	20	17	329	51	47	60	35	70	-54	-58	-45
Average	**103,38**			**223**	**50**	**47**	**56**	**35**	**70**	**-55**	**-58**	**-49**
2030	175,32	20	17	406 (NP)	105	103	118	35	70	0	-2	13
2030	175,32	20	17	406 (EEX)	137	131	154	35	70	32	26	49

Tabel 2: Results for DTU plant (360 MW turbine) including transmission tarifs

Year	Main price input				Net profit before fixed costs			Fixed Costs		Resulting net profit		
	Natural	Variable Opr. Costs		Average	Reg 4	Reg 5	Reg 6	O&M	Invest	Reg 4	Reg 5	Reg 6
	Gas	Turbine	Compress.	El-price								
	DKK/MWh				MDKK	MDKK	MDKK	MDKK	MDKK	MDKK	MDKK	MDKK
2000	79,56	24	32	122	24	26	30	35	70	-81	-79	-75
2001	103,93	24	32	177	20	19	24	35	70	-85	-86	-81
2002	86,83	24	32	189	54	52	60	35	70	-51	-53	-45
2003	91,22	24	32	250	74	67	83	35	70	-31	-38	-22
2004	88,20	24	32	214	15	11	19	35	70	-90	-94	-86
2005	120,17	24	32	277	73	73	84	35	70	-32	-32	-21
2006	153,72	24	32	329	44	41	52	35	70	-61	-64	-53
Average	**103,38**			**223**	**43**	**41**	**50**	**35**	**70**	**-62**	**-64**	**-55**
2030	175,32	24	32	406 (NP)	96	94	108	35	70	-9	-11	3
2030	175,32	24	32	406 (EEX)	127	121	144	35	70	22	16	39

Tabel 3: Results for DTU plant (360 MW turbine) including taxes (PSO and Electricity consumption)

Year	Main price input				Net profit before fixed costs			Fixed Costs		Resulting net profit		
	Natural	Variable Opr. Costs		Average	Reg 4	Reg 5	Reg 6	O&M	Invest	Reg 4	Reg 5	Reg 6
	Gas	Turbine	Compress.	El-price								
	DKK/MWh				MDKK	MDKK	MDKK	MDKK	MDKK	MDKK	MDKK	MDKK
2000	79,56	24	710	122	4	5	6	35	70	-101	-100	-99
2001	103,93	24	719	177	1	1	5	35	70	-104	-104	-100
2002	86,83	24	705	189	3	4	7	35	70	-102	-101	-98
2003	91,22	24	706	250	13	13	18	35	70	-92	-92	-87
2004	88,20	24	714	214	0	0	0	35	70	-105	-105	-105
2005	120,17	24	792	277	5	4	8	35	70	-100	-101	-97
2006	153,72	24	730	329	0	0	1	35	70	-105	-105	-104
Average	**103,38**			**223**	**4**	**4**	**6**	**35**	**70**	**-101**	**-101**	**-99**
2030	175,32	24	682	406 (NP)	9	10	15	35	70	-96	-95	-90
2030	175,32	24	682	406 (EEX)	28	28	36	35	70	-77	-77	-69

Tabel 4: Results for DTU plant (360 MW turbine) kombineret spot- og regulerkraftmarkedspriser

Year	Main price input				Net profit before fixed costs			Fixed Costs		Resulting net profit		
	Natural	Variable Opr. Costs		Average	Reg 4	Reg 5	Reg 6	O&M	Invest	Reg 4	Reg 5	Reg 6
	Gas	Turbine	Compress.	El-price								
	DKK/MWh				MDKK	MDKK	MDKK	MDKK	MDKK	MDKK	MDKK	MDKK
2000	79,56	24	32	121	38	37	45	35	70	-67	-68	-60
2001	103,93	24	32	165	31	26	38	35	70	-74	-79	-67
2002	86,83	24	32	181	68	65	80	35	70	-37	-40	-25
2003	91,22	24	32	221	83	81	96	35	70	-22	-24	-9
2004	88,20	24	32	212	24	19	28	35	70	-81	-86	-77
2005	120,17	24	32	293	116	117	135	35	70	11	12	30
2006	153,72	24	32	318	77	72	91	35	70	-28	-33	-14
Average	**103,38**			**216**	**62**	**60**	**73**	**35**	**70**	**-43**	**-45**	**-32**
2030	175,32	24	32	406 (NP)	154	152	172	35	70	49	47	67
2030	175,32	24	32	406 (EEX)				35	70	-105	-105	-105

Tabel 5: Results for DTU plant (360 MW turbine) kun regulerkraftmarked												
Year	Main price input				Net profit before fixed costs			Fixed Costs		Resulting net profit		
	Natural	Variable Opr. Costs		Average	Reg 4	Reg 5	Reg 6	O&M	Invest	Reg 4	Reg 5	Reg 6
	Gas	Turbine	Compress.	El-price								
	DKK/MWh				MDKK	MDKK	MDKK	MDKK	MDKK	MDKK	MDKK	MDKK
2000	79,56	24	32	121	13	12	17	35	70	-92	-93	-92
2001	103,93	24	32	165	9	8	13	35	70	-96	-97	-96
2002	86,83	24	32	181	23	21	29	35	70	-82	-84	-82
2003	91,22	24	32	221	28	26	36	35	70	-77	-79	-77
2004	88,20	24	32	212	9	7	12	35	70	-96	-98	-96
2005	120,17	24	32	293	25	24	44	35	70	-80	-81	-80
2006	153,72	24	32	318	32	26	44	35	70	-73	-79	-73
Average	**103,38**			**216**	**20**	**18**	**28**	**35**	**70**	**-85**	**-87**	**-85**
2030	175,32	24	32	406 (NP)	28	27	51	35	70	-77	-78	-77
2030	175,32	24	32	406 (EEX)								

Tabel 6: Results for DTU plant (360 MW turbine) kun regulerkraftmarked												
Year	Main price input				Net profit before fixed costs			Fixed Costs		Resulting net profit		
	Natural	Variable Opr. Costs		Average	Reg 4	Reg 5	Reg 6	O&M	Invest	Reg 4	Reg 5	Reg 6
	Gas	Turbine	Compress.	El-price								
	DKK/MWh				MDKK	MDKK	MDKK	MDKK	MDKK	MDKK	MDKK	MDKK
2000	79,56	24	32	121	13	12	17	35	70	-92	-93	-92
2001	103,93	24	32	165	9	8	13	35	70	-96	-97	-96
2002	86,83	24	32	181	23	21	29	35	70	-82	-84	-82
2003	91,22	24	32	221	28	26	36	35	70	-77	-79	-77
2004	88,20	24	32	212	9	7	12	35	70	-96	-98	-96
2005	120,17	24	32	293	25	24	44	35	70	-80	-81	-80
2006	153,72	24	32	318	32	26	44	35	70	-73	-79	-73
Average	**103,38**			**216**	**20**	**18**	**28**	**35**	**70**	**-85**	**-87**	**-85**
2030	175,32	24	32	406 (NP)	28	27	51	35	70	-77	-78	-77
2030	175,32	24	32	406 (EEX)								

Tabel 7: Results for DTU plant (360 MW turbine), kompressor på spotmarket og turbine på regulerkraft												
Year	Main price input				Net profit before fixed costs			Fixed Costs		Resulting net profit		
	Natural	Variable Opr. Costs		Average	Reg 4	Reg 5	Reg 6	O&M	Invest	Reg 4	Reg 5	Reg 6
	Gas	Turbine	Compress.	El-price								
	DKK/MWh				MDKK	MDKK	MDKK	MDKK	MDKK	MDKK	MDKK	MDKK
2000	79,56	24	32	121	14	12	19	35	70	-91	-93	-86
2001	103,93	24	32	165	9	7	15	35	70	-96	-98	-90
2002	86,83	24	32	181	28	23	38	35	70	-77	-82	-67
2003	91,22	24	32	221	35	27	47	35	70	-70	-78	-58
2004	88,20	24	32	212	10	6	16	35	70	-95	-99	-89
2005	120,17	24	32	293	53	47	68	35	70	-52	-58	-37
2006	153,72	24	32	318	39	30	57	35	70	-66	-75	-48
Average	**103,38**			**216**	**27**	**22**	**37**	**35**	**70**	**-78**	**-83**	**-68**
2030	175,32	24	32	406 (NP)	61	54	77	35	70	-44	-51	-28
2030	175,32	24	32	406 (EEX)								

Appendiks A

Energy System Analysis of CAES Technologies in the Danish Energy System with High Penetration of Fluctuating Renewable Energy Sources

(Paper initially presented at the Energex 2006 Conference in Stavanger, Norway and Submitted to the Applied Energy Journal on 29 Maj, 2007)

Energy system analysis of compressed air energy storage in the Danish energy system with high penetration of renewable energy sources

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Abstract

In 2005, wind power supplied 19% of the 36 TWh annual electricity demand in Denmark, while 50% was produced at combined heat and power plants (CHP). The installed wind turbine capacity in Western Denmark exceeds the local demand at certain points in time. So far, excess production has been exported to neighbouring countries. However, plans to expand wind power both in Denmark and in its neighbouring countries could restrain the export option and create transmission congestion challenges. This results in a need to increase the flexibility of the local electricity system. Compressed Air Energy Storage (CAES) has been proposed as a potential solution for levelling fluctuating wind power production and maintaining system balance. This paper analyses the energy balance effects of adding CAES to the Western Danish energy system. Results show that even with an unlimited CAES plant capacity, excess power production is not eliminated because of the high percentage of CHP production. The optimum wind power penetration for maximum CAES operation is found to be around 55%. The minimum storage size for CAES to fully eliminate condensing power plants operation in the optimized system is over 500 GWh, which corresponds to a cavern volume of around 234 $M.m^3$ at an average pressure of 60 bars. Such a storage size would be technically and economically unfeasible. The analysis, however, did not include the potential role of a CAES plant in providing regulating power services.

Keywords: Compressed air, Electricity storage, Wind power, Energy system analysis.

1. Introduction

In 2005, wind energy provided 19% of the electricity demand in Denmark [1]. Wind power penetration in Western Denmark[*] was higher than the national average and reached up to 24% of the local electricity demand of 25 TWh [2]. This paper focuses on Western Denmark, where the current total installed wind turbine capacity is around 2400 MW, of which 213 MW is offshore. This compares to an electricity consumption that varied between 1,560 MW and 3,600 MW in 2005 [3]. With high wind velocities, wind power production can exceed the local electricity demand. This is illustrated in Figure 1 which shows an example of the local electricity demand and wind power production for two days in 2005. Moreover, changing wind velocities create a need for a fast reserve capacity to regulate the power imbalances.

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[*] Western Denmark includes Jutland and the island of Fyn and is currently not electrically connected to Eastern Denmark which includes the island of Zealand on which Copenhagen is located.

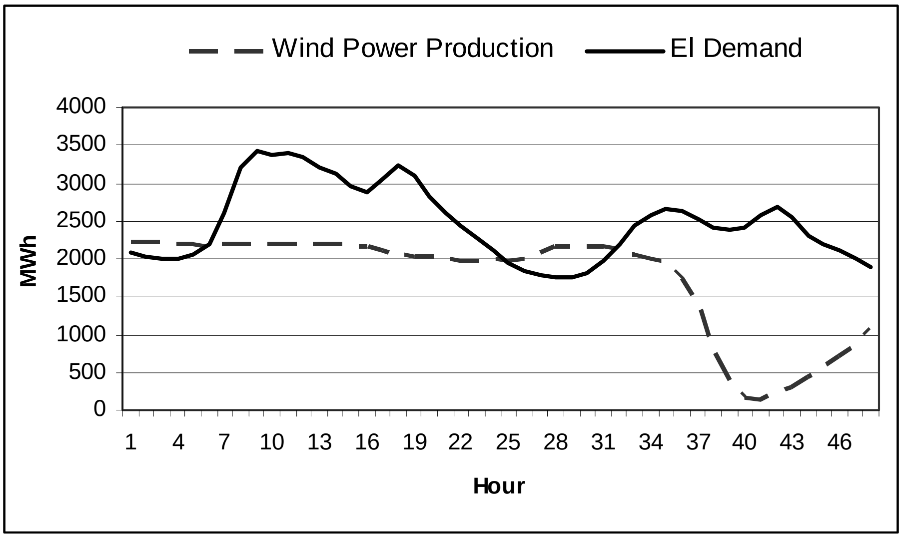

Figure 1: Net electricity demand and wind power production in Western Denmark on 07/01/05 and 08/01/05 (Friday and Saturday) [3].

The ability of the electricity system to accommodate this high level of wind energy is further complicated by the high percentage of decentralized small-scale CHP power plants with a total capacity of 1593 MW [4]. Prior to March 2004, most decentralized plants enjoyed priority production status with a fixed payment based on a triple tariff system. This resulted in an operation that rarely reflected electricity demand and market prices. Following the parliamentary agreement of March 29, 2004, all major CHP plants exceeding 5 MW were required to operate on market conditions. As an initial result, this operation has shown an improved system balance. However, as both Denmark and its neighbouring countries have plans to increase their wind production in the future, this could reduce the balancing and regulating power capacities available from abroad. From the socio-economic perspective and seen in relation to the security of supply, local reserves are preferred; especially since excess wind power is sold at low prices and bought again later at higher prices.

To solve this problem on a long term with even more wind power in the system, a variety of different technologies can be utilized [5,6,7]. Electricity storage is one of the possible solutions to the challenges mentioned above. However, very few technologies tend to be economical at a utility scale [8,9,10] . At a local level in Denmark, given the absence of pumped hydro potential, one of the potentially feasible technologies available nowadays is compressed air energy storage (CAES) [11].

CAES is a modification of the basic gas turbine (GT) technology, in which low cost electricity is used for storing compressed air in an underground cavern. The air is then heated and expanded in a gas turbine to produce electricity during peak demand hours. As it derives from GT technology, the CAES technology is readily available.

During the 1970s, the CAES technology was extensively discussed and several feasibility studies were conducted mainly in Europe and the USA [12]. Original works focused on utilizing CAES for peak shaving and load levelling applications in conjunction with base load nuclear and thermal power plants [13,14]. Only two CAES plants have been constructed in the world since; one in Germany and the other in the USA of 390 MW and 110 MW turbine capacities, respectively.

Growing concerns related to the environment and security of supply in the 1990s, however, have led to many proposals perceiving CAES as a technology that could cover the intermittency of renewable energy sources. Several papers have been published on the wind/CAES hybrid system. Bullough et al. analyse the technical development and economic feasibility of an Advanced Adiabatic CAES (AA-CAES) system in various European countries with the EU target of 20% renewable energy by 2020 as a basis [15] . In his paper, Denholm suggests a fully renewable base load power plant using a combination of wind power, CAES, and biofuels [16]. The economic competitiveness of a base load wind/CAES is analysed by DeCarolis and Keith in [17]. A hybrid wind/CAES system is also proposed by Cavallo as a compensation for the intermittency of wind power [18].

This paper analyses the potential impact of a CAES plant on the electricity system in Western Denmark. In particular, the paper focuses on the issue of dealing with excess electricity production. The analysis is performed using the EnergyPLAN model, and the results show that CAES alone has a limited potential to allow an increase in installed wind power capacity.

2. Methodology

The large-scale integration of wind power has been analyzed by modelling the Western Danish collective energy system (electricity and district heating) on the EnergyPLAN computer model developed at Aalborg University. The EnergyPLAN model is a deterministic input/output simulation model. General inputs are demands, capacities and a number of optional regulation strategies, emphasising import/export and excess electricity production. Outputs are energy balances and resulting annual production, fuel consumption and import/export. The model is available online along with documentation material [19].

The energy system in the EnergyPLAN model includes heat production from solar thermal power, industrial CHP, CHP units, heat pumps and heat storage and boilers. District heating supply is divided into three groups of boiler systems and decentralised and centralised CHP systems. Additional to the CHP units, the systems include electricity production from renewable energy, i.e. photovoltaic and wind power input divided into onshore and offshore, as well as traditional power plants (condensation plants).

The model is simple in the respect that it aggregates all units in each of the mentioned types in the modelled region into one unit with average properties. This means that the differences between the single units and the transmission among them are not considered. On the other hand, the model is advanced in the respect that it uses detailed hourly distributions of heat demands, electricity demands, wind production etc. to analyse the behaviour of the entire system hour by hour for a whole year. Various constraints, operational strategies and changes to the system can be introduced and compared.

The inaccuracy caused by the aggregation has been evaluated by testing the effect of replacing the single CHP unit with ten different interconnected units, each with properties related to actual Danish plants with differences in size, amount of heat storage, etc. The differences between these two situations were found to correspond to changes in the specifications for the CHP unit of app. 3%, and such differences are now being compensated for in the EnergyPLAN model.

The model requires four sets of input for the technical analysis. The first set is the annual district heating consumption and the annual consumption of electricity, including flexible demand and electricity consumption from the transport sector, if any. The second set is the capacity of photovoltaic and wind power, including a moderation factor, in order to adjust the relationship between the wind capacity and the correlating electricity production. This part also defines solar thermal and industrial CHP heat production inputs to district heating. The third set consists of capacities and operation efficiencies of CHP units, power stations, boilers and heat pumps. Finally, the last set specifies some technical limitations; namely the minimum CHP and power plant percentage of the load needed in order to retain grid stability. Furthermore, it includes the maximum heat pump percentage of the heat production, in order to achieve the specified efficiency of the heat pumps.

The model emphasises the consequences of different regulation strategies. Basically, the technical analyses distinguish between the two following strategies:

- *Regulation Strategy I: Meeting Heat Demand:* In this strategy, all units produce solely according to the heat demands. In district heating systems without CHP, the boiler simply supplies the difference between the district heating demand and the production from solar thermal power and industrial CHP. For district heating with CHP, the units are given priority according to the following sequence: Solar thermal power, industrial CHP, CHP units, heat pumps and peak load boilers.

- *Regulation Strategy II: Meeting both Heat and Electricity Demands:* When choosing strategy II, the export of electricity is minimised mainly by replacing CHP heat production by boilers or by the use of heat pumps. This strategy increases electricity consumption and decreases electricity production simultaneously, as the CHP units must decrease their heat production. With the use of extra capacity at the CHP plants combined with heat storage capacity, the production at the condensation plants is minimised by replacing it with CHP production.

In all strategies, the model takes a number of restrictions into consideration, such as:

- the certain degree of grid-stabilising capacity needed in the system
- bottlenecks in external transmission capacity
- strategies for avoiding critical surplus production
- maximum percentage of heat production from heat pumps

3. Energy System Description

The reference energy system scenario is based on the current Western Danish electricity system (Table 1). The assumed wind turbine capacity includes plans to expand the offshore capacity up to 500 MW. For the purpose of analyzing the excess electricity production (EEP), the system is isolated from neighbouring systems by removing any transmission capacity.

In the alternative scenario, a CAES plant is added to the system. The reference CAES plant considered consists of a 214 MW compressor train and a 361 MW expansion train. The cavern size is 700,000 m^3 corresponding to 1478 MWh. The compressor efficiency is 69%, resulting in a 10-hour compression starting from an empty storage. The expansion requires

149 MWh of compressed air energy in combination with 434 MWh of fuel firing to produce 361 MWh of electricity. This in turn translates into around 10 hours of expansion capacity starting at a full storage.

Table 1: Main inputs for the reference energy system scenario in the EnergyPLAN model.

Heat Demand	23.51	TWh
Fixed El. Demand	24.87	TWh
Decentralized CHP	1450	MW
Decentralized Boiler	7000	MJ/s
Dec. Heat Storage	15	GWh
Centralized CHP	1300	MW
Cen. Condensing	3200	MW
Cent. Boiler	7000	MJ/s
Cent. Heat Storage	10	GWh
Onshore Wind	2500	MW
Onshore Prod.	6.05	MWh
Offshore Wind	500	MW
Offshore Prod	2.11	MWh
Annual Wind %	33	%

4. Simulation Results

Figure 2 shows the annual power balance of the reference energy system (without CAES). The figure is generated by increasing the offshore wind turbine capacity from 500 MW to 4500 MW, which corresponds to a scenario in which 100% of the 25 TWh fixed electricity demand is met by wind power. The figure shows that, as the wind penetration increases, the production of both CHP and condensing power plants decreases, while the EEP increases. The decrease in CHP production is a result of following the regulation strategy 2 in the EnergyPLAN simulations, which leads to the replacement of CHP production by boilers in order to meet the heat demand. If regulation strategy 1 was followed instead, the CHP production would have remained constant, thus leading to even higher EEP.

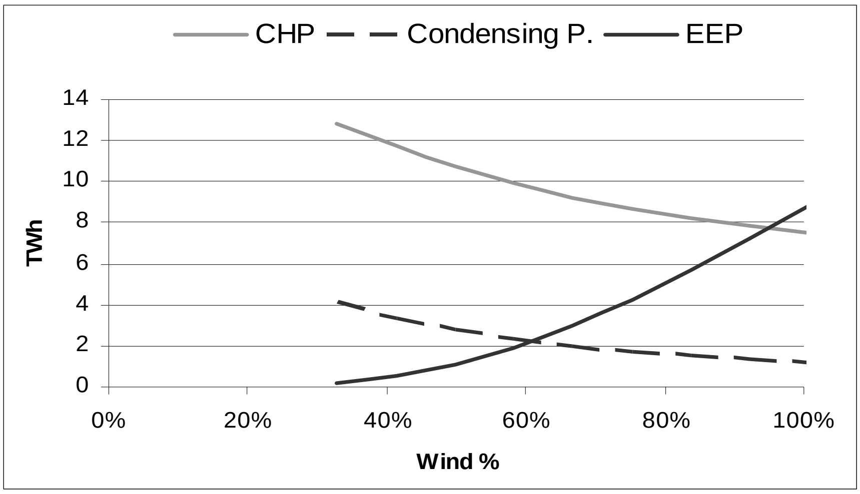

Figure 2: Power balance of the reference energy system at various wind power penetrations for a fixed annual electricity demand of 25 TWh

The same simulation is repeated for a system including the reference CAES plant described in section 3, and the resulting EEP is shown in Figure 3. It can be seen that adding the CAES plant has an almost negligible effect in terms of reducing the EEP. In order to determine the influence of the CAES plant capacity, two further cases were plotted in Figure 3; the first being the reference CAES plant with infinite storage, and the second being an unlimited capacity for both the storage and the compressor/turbine systems. Both curves indicate that the ability of CAES to relocate excess wind power decreases with increasing power penetration. The unlimited capacity allows the CAES plant to eliminate EEP up to around 50%, beyond which the heat-driven CHP production imposes a limiting factor on the CAES operation, as illustrated in Figure 4.

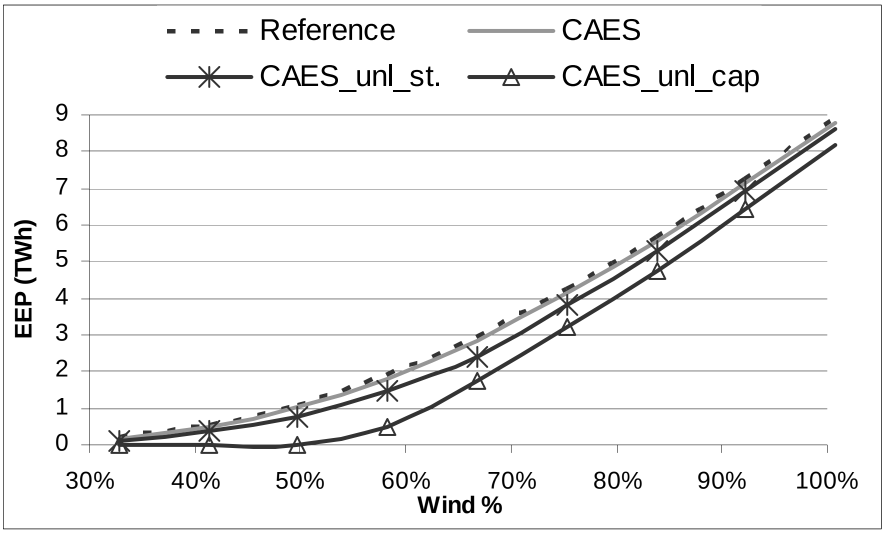

Figure 3: EEP of the reference system compared to adding: 1- The reference CAES plant. 2- The reference CAES plant with unlimited storage. 3 – A CAES plant with unlimited compressor, storage, and turbine capacities.

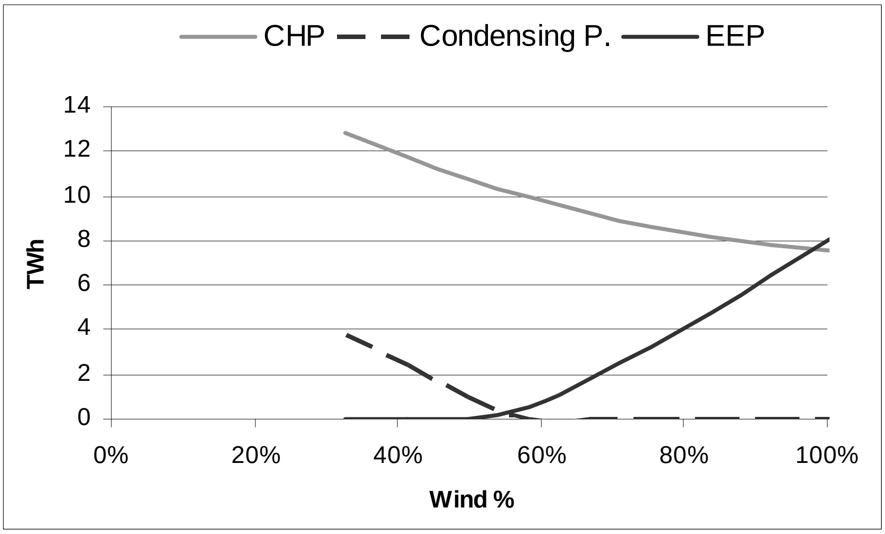

Figure 4: Power balance of a system including a CAES plant with unlimited compressor, turbine, and storage capacities.

The reference CAES plant compressor and turbine operations are shown in Figure 5. Note that while the operation increases with the wind percentage, it tends to peak towards the end before decreasing again. When examining the hourly behaviour of the CAES plant it can be seen that the relatively low operation is a result of two main factors:

- The limited amount of EEP at low wind penetration leading to an empty storage during hours of potential CAES turbine production.
- The excess amount of EEP at high wind penetration leading to a full storage during hours of potential CAES compression.

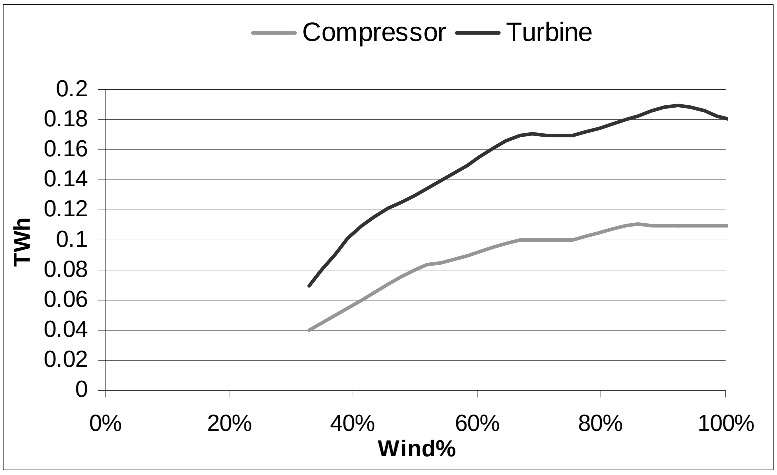

Figure 5: CAES compressor and turbine operation at various wind power penetrations for the Reference CAES plant capacities.

Figure 6 shows the potential compressor/turbine operation both in hours and MWh. The potential compression hours (PCH) are the hours with full storage and an EEP above 0. The corresponding potential compression operation (PCO) is the sum of the EEP during those hours. The potential expansion hours (PEH), on the other hand, are the hours with an empty storage and condensing power production above 0. The corresponding potential expansion operation (PEO) is the sum of the condensing power production during those hours. It can be seen that, at low wind power penetration, the limiting factor is the emptiness of the storage at hours of potential expansion. As wind penetration increases, the limiting factor becomes the saturation of the storage during hours of compression.

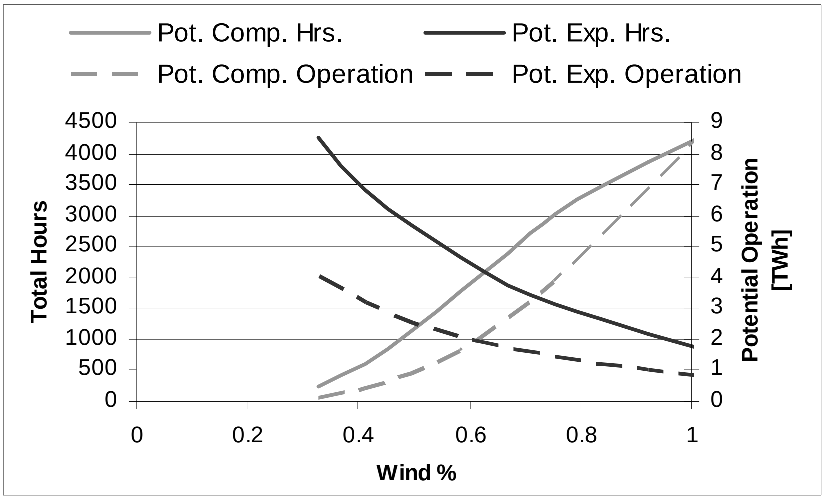

Figure 6: Potential compression and expansion hours and operation for the reference CAES plant capacities.

Figure 7 shows the compressor and turbine operation for a CAES plant with infinite compressor, turbine, and storage capacities. While the overall compressor and turbine operation is higher than the reference plant in figure 5, a similar peaking behaviour is displayed indicating the existence of an optimum electricity system for a CAES plant.

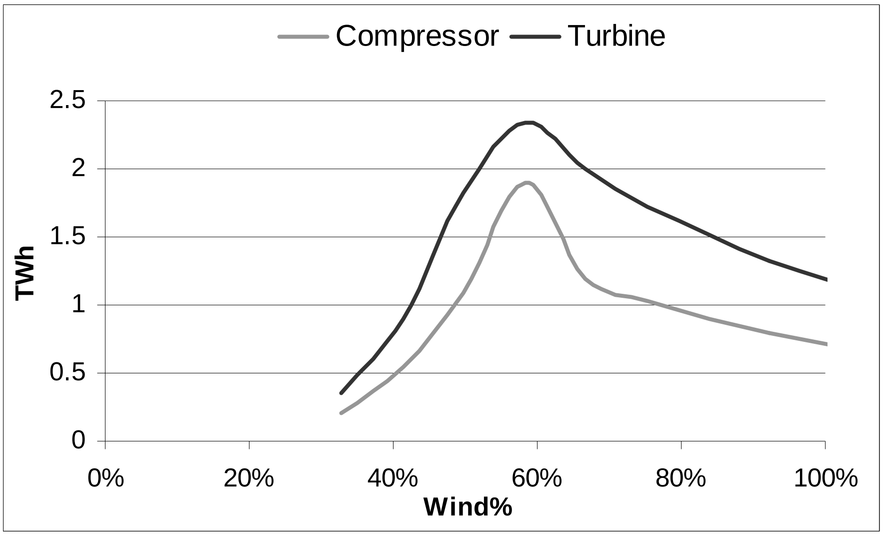

Figure 7: CAES compressor and turbine operation at various wind power penetrations for a CAES plant with infinite component capacities.

5. CAES/Electricity System Design

The results above were used for defining an optimum CAES/electricity system combination that minimizes the EEP. Given the compressor/turbine efficiencies, it is found that the electricity ratio of the CAES system is 0.6. In other words, every 0.6 MWh compressor consumption produces 1 MWh electricity output.

With the aim of replacing the condensing power production, the first step in designing the optimum system is to ensure that the total annual EEP is 60% that of the condensing power production. This is found to be the case at a wind penetration of 55% (2500 MW and 1780 MW installed wind capacity onshore and offshore, respectively).

The next step is to determine the CAES plant capacity that could fully eliminate the EEP and condensing power production. Figures 8 and 9 show the CAES plant operation, the EEP, and the condensing power plants operation of two different CAES systems with varying storage capacity. In this case, it is assumed that the CAES plant efficiencies do not change with the changing capacities. The first CAES system is the reference CAES plant discussed in section 3, whereas the second system has a compressor/turbine capacity of 2600MW/2700 MW, respectively, corresponding to the maximum EEP and condensing power values in the reference system.

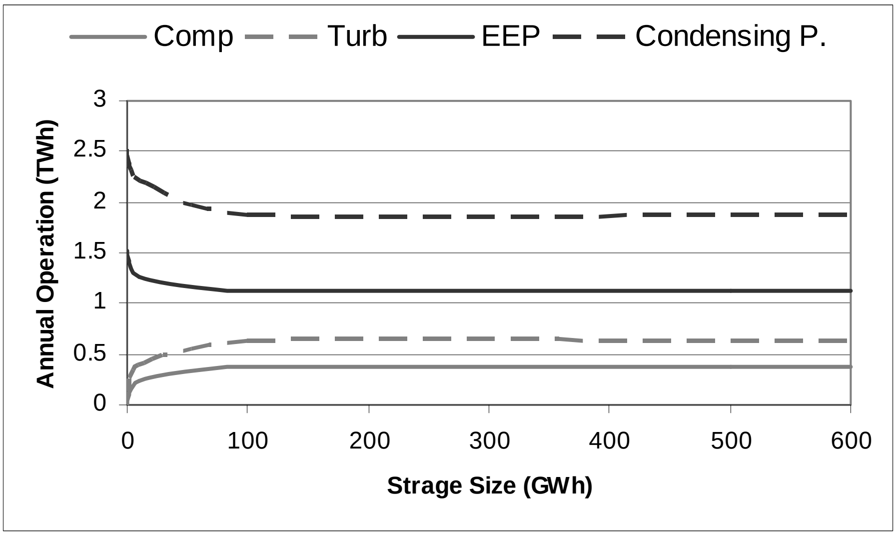

Figure 8: Performance of a 214/361 compressor/turbine system at various storage sizes

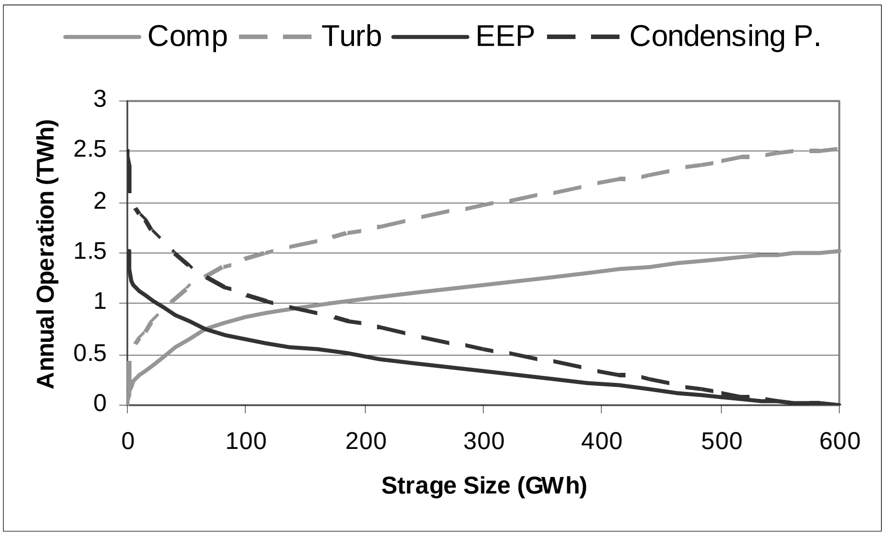

Figure 9: Performance of a 2600/2700 compressor/turbine system at various storage sizes

It can be seen that for the smaller system, the increase of the storage to above 80 GWh has no effect on the CAES plant operation. For the larger CAES system, however, it is possible to fully eliminate the EEP and condensing power by increasing the storage up to 600 GWh.

6. Conclusion

The ability of CAES to eliminate excess electricity production from wind power in the Danish energy system was analyzed using the EnergyPLAN computer model. It was found that a standard CAES plant capacity corresponding to that of the existing plants in Huntorf and Alabama has negligible effects on improving the energy system balance at all ranges of wind penetration. For low wind penetration, the main CAES operational barrier is the lack of sufficient excess electricity; while for high penetration, the main barrier is the lack of discharging hours in a system with high CHP capacity.

An optimum CAES/electricity system combination was found. The optimum system has around 55% wind penetration. However, the required storage value needed for CAES to fully eliminate condensing power plant operation is found to be over 500 GWh. Considering the fact that a 1,478 GWh storage corresponds to 700,000m^3, a 500 GWh storage corresponds to around 234 M.m^3, which could be too large to be technically and economically feasible.

It is therefore concluded that, seen from a system balance perspective, CAES alone is not able to eliminate excess production. The study, however, did not consider the importance of a CAES plant in providing regulating power, an issue to be studied later on.

7. Acknowledgements

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Appendiks B

Compressed Air Energy Storage in Denmark; A Feasibility Study and an Overall Energy System Analysis
(*Paper presented at the World Renewable Energy Congress, Florence 2006)*

Compressed air energy storage in Denmark; a feasibility study and an overall energy system analysis

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Abstract

Compressed air energy storage system (CAES) is a technology which can be used for integrating more fluctuating renewable energy sources into the electricity supply system. On a utility scale, CAES has a high feasibility potential compared to other storage technologies. Here, the technology is analysed with regard to the Danish energy system. In Denmark, wind power supplies 20% of the electricity demand and 50% is produced by combined heat and power (CHP). The operation of CAES requires high electricity price volatility. However, in the Nordic region, large hydro capacities have so far kept the prices from fluctuating to the extent that CAES investments have not been considered feasible. This report studies the effect of technological development and possible future price development of investments in CAES plants of various capacities. It is found that advanced high-efficiency CAES plants are likely to become feasible in the near future.

Keywords: Compressed air energy storage, electricity market, regulating power

1. Introduction

In 2004, wind energy provided 32% of the electricity consumption in Western Denmark. The current total installed wind turbine capacity is 2400 MW, of which 213 MW is offshore. This compares to an electricity consumption that varies between 1,150MW and 3,800MW. With high wind velocities, wind power production can exceed the local electricity demand. Moreover, the changing wind velocity gives rise to a large need of fast reserve capacity to regulate the power imbalances. The ability of the electricity system to accommodate this high level of wind energy is further complicated by the high percentage of decentralized small-scale CHP power plants with a total capacity of 1593 MW.

The system operator in Western Denmark (Energinet.dk) has so far been able to deal with these challenges by using both local thermal resources and connections to neighbouring electricity systems. Following a new legislation, major CHP plants exceeding 5 MW are gradually operating on market conditions. As an initial result, this operation has shown an improved system balance. Such CHP plants used to operate in accordance with a triple tariff system which was not influenced by system unbalances coming from e.g. wind power [1]. However, as neighbouring countries have plans to increase their wind production in the future, this could reduce the regulating capacities available from abroad. From the perspective of socio-economy and security of supply, local reserves are preferred, especially since excess wind power is sold at low prices and bought again later at higher prices.

To solve the problem on a long term with even more wind power in the system, one will have to combine a variety of different technologies [2-6].

Electricity storage is one of the possible solutions to the challenges mentioned above. However, very few technologies tend to be economical on a utility scale. At a local level in Denmark, one of the potentially feasible technologies available nowadays is *compressed air energy storage* (CAES).

Compressed air energy storage (CAES) is a modification of the basic gas turbine (GT) technology, in which low cost electricity is used for storing compressed air in an underground cavern. This air is then heated and expanded in a gas turbine to produce electricity during peak demand hours. As it derives from GT technology, CAES technology is readily available and reliable. Two plants have been constructed in the world so far; one in Germany and one the USA of 390 MW and 110 MW turbine capacities, respectively.

Recent feasibility studies have shown that a CAES plant investment in Denmark is economically unfeasible with the current electricity prices [7]. This is mainly due to the connection with the hydro-dominated Nordic region which reduces price volatility.

However, future system analyses show an expected increase in both average electricity prices and price volatility, in particular after year 2012 in the case that no investments in new power plants are made. This increase arises from a combination of projected increase in electricity demand and a rise in CO_2 quota prices [8]. On the basis of these future price analyses, the feasibility of three CAES technological scenarios is studied in this paper from a business- economic perspective.

2. CAES Plant Modelling

A mathematical model was developed for simulating the behaviour of a CAES plant on the electricity market. The model is divided into two parts: technical model and operational model.

Technical Model

The technical model follows an object-oriented approach. A thermodynamic model is constructed for the main CAES plant components (compressors, inter and after coolers, throttling valves, storage cavern, combustion chambers, turbines, a regenerator, and a motor/generator unit).

A generic CAES plant design is then constructed on the basis of data from the CAES plant in Alabama [9]. The plant consists of a four-stage compression and a two-stage expansion including a regenerator (figure 1). The components are cascaded in the model where the output of one unit is used as the input to another.

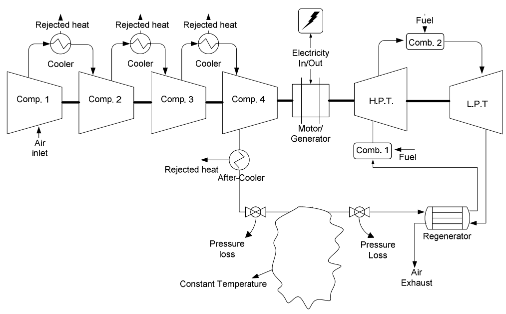


Figure 1: Generic CAES plant design used in the mathematical model.

The behaviour of the individual compressor and turbine units was described using isentropic efficiencies. The storage was assumed to be air-tight with constant wall temperature at 35˚C [10].

Three main performance indicators were used to describe the efficiency of the plant:

- The electricity ratio (**El.Ratio**), defined as the amount of electrical power input per electricity unit output.
- The **Fuel Ratio** defined as the heat value of the utilized fuel per electricity unit output.
- The **Heat Ratio** defined as the wasted heat in the compression and expansion process per electricity unit output for a reference temperature of 30˚C.

Operational Model

The operational model is concerned with optimizing the operation of the technical model on the electricity market. For this purpose, a deterministic price time series is used.

The model assumes that the plant operator develops a strategy that includes a "maximum purchase price" for air compression and a "minimum bidding price" for power generation. The optimum strategy is then found by individually varying the purchase and bidding prices in order to reach a maximum variable operational income (VOI) during the specified period. The VOI is calculated as the difference between the earnings made on the electricity market and the costs incurred by natural gas, electricity consumption, start-up costs, and operational costs.

On the basis of the time series shown in figure 2, the year is divided into four periods. The optimum purchase and bidding prices are calculated for each period and the Annual Variable Operational Income (AVOI) is found as the sum of the resulting VOI.

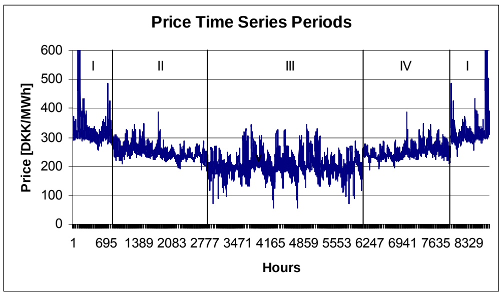


Figure 2: Synthetic price time series based on the 2002 system prices in Western Denmark.

Iteration is used for ensuring that the storage content is the same in the beginning and in the end of the year. Besides, a sensitivity factor is included to account for the effect of the extra consumption/ production capacity incurred by the CAES plant on the system prices.

3. CAES Future Scenarios

Three main technical scenarios were used for simulating a CAES plant in Denmark. The first is the **Current Day Technology** (CDT) scenario, which is based on available data from the Alabama CAES plant [7,9].

The **State-of-the-Art Technology** (SOAT) scenario is based on the General Electric 109H system gas turbines. This advanced turbine model has a firing temperature of up to 1430˚C and a combined cycle efficiency that exceeds 60% [11].

Finally, the **Advanced Technology** (AT) scenario is an attempt to reduce the fuel consumption of the SOAT by having a regenerator with 0.9% effectiveness (as compared to 0.7% in the previous scenarios) and having heat storage in which 50% of the heat rejected by the compressor can be re-used to preheat the air during expansion. Table 1 summarizes the main technical differences between the three scenarios.

Table 1: High and Low Pressure Turbine (HPT & LPT) firing temperature (˚C), regenerator effectiveness, and compression waste heat utilization factor for the 3 technological scenarios.

	CDT	SOAT	AT
HPT Ti	538	882	882
LPT Ti	871	1428	1428
Regen. Effect.	70%	70%	90%
Waste heat use	None	None	50%

Figure 3 shows the main performance indicators of the 3 scenarios. It is seen that the SOAT represents a reduction in the electricity ratio compared to the CDT scenario. This means a lower amount of compressed air for the same turbine power output. The AT, on the other hand, represents a reduction in the fuel ratio compared to SOAT, with the electricity ratio being the same.

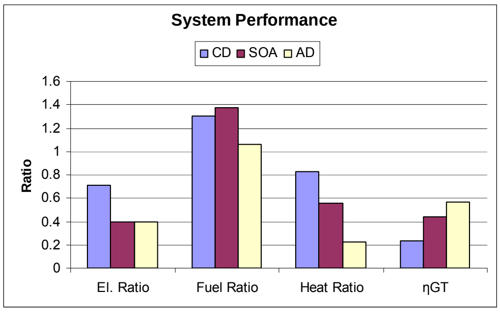


Figure 3: The electricity ratio, fuel ratio, heat ratio, and standard gas turbine efficiency of the three technological scenarios employed.

4. Electricity Price Future Scenario

The system price development is based on a recent study done by the Risø National Laboratory (figure 4). The study assumes no major power plant investments will be made in the Nordic region apart from the plants already planned. The study also projects an increase in electricity demand and an increase in the price of the CO_2 quota from 6.7 Euro to 13.4 Euro in 2012.[8]

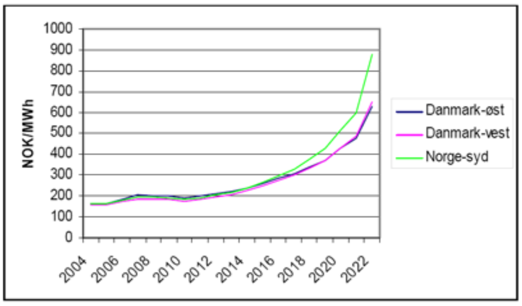
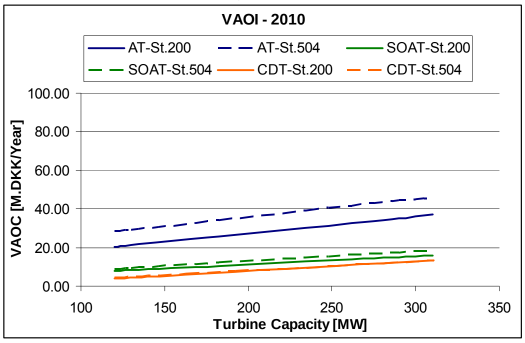
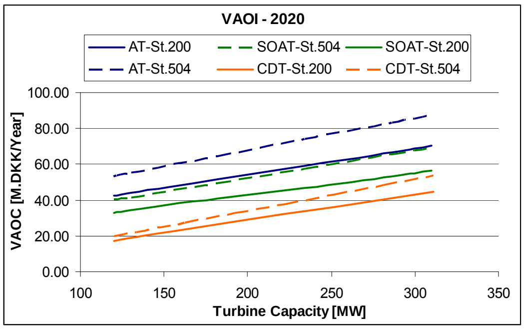


Figure 4: Mean annual prices in Norwegian Krones (1NOK≈0.127Euro) as found in [8] for East and West Denmark and South Norway

5. Simulation Results

The VAOI results of the three technologies at two different storage sizes are shown in Figures 5-6 for the years 2010 and 2020. Both figures show that better technology results in higher VAOI. Besides, it is seen that the VAOI increases proportionally to the turbine capacity.





Figures 5-6: VAOI as a function of the turbine capacity for storage sized of 200,000m^3 and 504,000m^3 for the years 2010 and 2020.

Figure 7 shows the resulting annual turbine operational hours for the years 2010 and 2020 for the SOAT and the AT. For a small storage size of 200,000m^3, the number of operational hours is barely changed between the years 2010 and 2020 for both technologies. For the larger storage, however, the AT tends to operate a larger amount of hours in 2010.

It can be concluded that with low price fluctuation, efficiency and storage size act as limiting factors to the possible amount of operation. As prices fluctuate more, the storage size becomes the dominant factor limiting the number of operational hours.

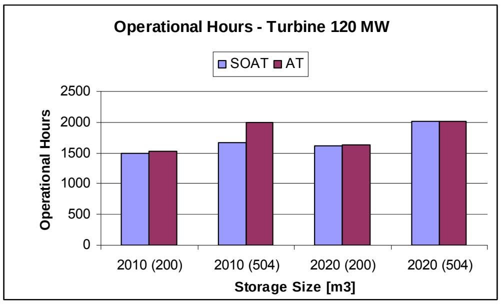


Figure 7: Number of turbine operational hours for a turbine capacity of 120 MW, storage sizes of 200,000m^3 and 504,000m^3, and years 2010 and 2020.

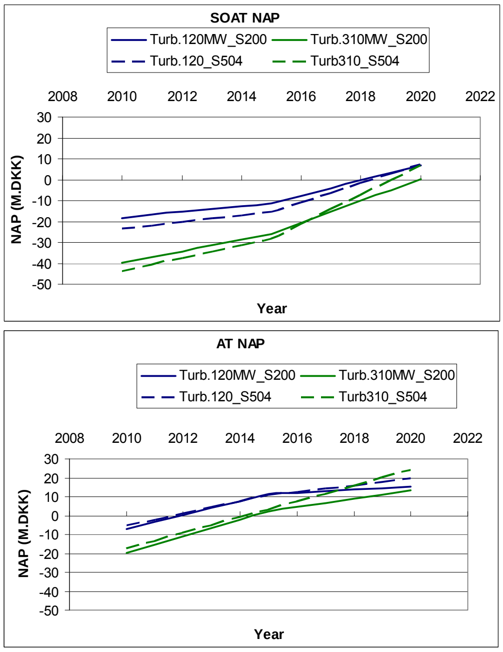
6. Feasibility Study

Table 1 summarizes the main investment costs, the fixed annual costs, and the key financial parameters used [7,12]

Table 2: Investment costs, fixed annual costs and other financial parameters [1,6]

	AT	Unit
Cavern [1]	321	DKK/m3
Comp.+ Intercooler	0.81	MDKK/MW
Turb + Burner + Regenerator	1.35	MDKK/MW
Motor/Generator	0.54	MDKK/MW
Land/Build/ Transactions	20	MDKK
Heat Storage	1700	DKK/m3
Fixed O&M [50 - 150MW]	75,000	DKK/MW/Yr
Fixed O&M [150 - 250MW]	45,000	DKK/MW/Yr
Fixed Cost [>250MW]	30,000	DKK/MW/Yr
Lifetime	30	Yrs
Interest Rate	4.00%	%

The investment costs are annualized using the Net Present Value relation and then subtracted from the VOAI. The results for the SOAT and the AT are shown in Figures 8-9. The results for the CDT are not shown since the investment is not feasible over all the years. It is noted, however, that the curves for the CDT display a similar trend to the one shown in Figures 10-11. The figures show, on the other hand, that the SOAT can become feasible around year 2018, whereas the AT may be feasible as early as in 2012.



Figures 8-9:: Net Annual Profit (NAP) for the SOAT and AT for two values of storage size (200,000 m^{3}and 504,000 m^3) and two turbine sizes (120 MW and 310 MW**).**

Figures 8-9 show that, during the initial years with low price volatility, a smaller turbine capacity benefits from the lower investment cost which gives a higher feasibility than the 310 MW. As the fluctuation increases, larger turbine sizes start gaining significance and tend to exceed the profit from the small turbine. This is because 310 MW turbines are able to benefit better from sharp price peaks than 120 MW turbines.

7. Conclusion

A feasibility study of various technical and future price scenarios was performed. For this purpose, a technical model was developed that could simulate the behaviour of a CAES plant. This model is used within an operational model that optimizes the CAES plant operation.

It is found that an improved CAES plant performance improves the feasibility of such a plant considerably. Advanced technology plants can be feasible as early as 2012. The recommended turbine capacity depends on the expected price average and fluctuation as well as the plant efficiency. At low price volatility, low turbine capacities are more feasible, whereas at higher price volatility, larger turbine capacities are more feasible. Concerning the storage size, larger storage sizes are favourable for advanced technology in all years and for state-of-the-art technology in years with high price volatility. For the current technology, the cavern size has little impact on the number of operational hours.

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Appendiks C

Previous working papers on the optimization of CAES operation on the electricity market

Economic Optimization of CAES on the Electricity Market

The aim of this part of the research is to develop an economic operation simulation tool that can optimize the CAES plant performance on the electricity market. The various models devised can be categorized into 3 main groups:

- Theoretical optimum models with unlimited Storage
- Practical Operational models
- Theoretical optimum models with limited storage,

The theoretical models are based on annual deterministic system price time series. Practical operational models, on the other hand, assume limited price knowledge of a maximum period of 24 hours ahead.

In order to compare the various models, we start by defining a reference scenario for the main technical and economic assumptions. We then move to describing and comparing the various models.

CAES Reference Scenario Definition

The aim is to establish a base scenario for the comparison of various CAES optimization models. The scenario includes both technical and economic values. Concerning the technical description, the following values were devised:

- Comp Capacity = 214 MW
- Comp efficiency = 0.691
- Storage = 1478 MWh
- Turb takes 149 MWh from the storage and 434 MWh fuel to produce 361 MWh El.

The above values were edited slightly in the scenario. For example, the storage was increased to 1480 MWh so that the full storage capacity can be utilized in pure "on/off" models with no part loads. Also the amount of air energy withdrawn from the cavern during expansion was slightly adjusted to equalize the number of compression and expansion hours per cycle. This is necessary in models that perform hour matching. The last assumption is minor, and it is seen that in the PowerStore report, the compression and expansion hours are taken to be the same. The final technical description of the model is as follows:

Technical Factors

Compressor Capacity = 214 MW
Turbine Capacity = 361 MW
Storage Capacity = 1480 MWh
Comp. Efficiency = 69.1 %

Fuel Ratio = $\frac{434\ MWh\ Fuel}{361\ MWh\ El\ Out} = 1.202$

Turbine Efficiency = $\frac{361\ MWh\ El\ Out}{CompCap \times CompEfficency} = 2.441$

Concerning the choice of the electricity price time series, the aim here is to choose a year that can be challenging in terms of model performance. When comparing the system prices in West Denmark for the years 2000 – 2005, it is seen that the year 2003 contains various price trends that include sharp peaks and low prices reaching down to 0 kr/MWh (Figure 1). The volatility of the prices in 2003 is thus high compared to other years. It is therefore chosen to use the 2003 system prices of Western Denmark in the base scenario. Since the energyPLAN model requires a time series of 8784 hours per year, the utilized time series included the addition of the prices of the first day to the end of the year.

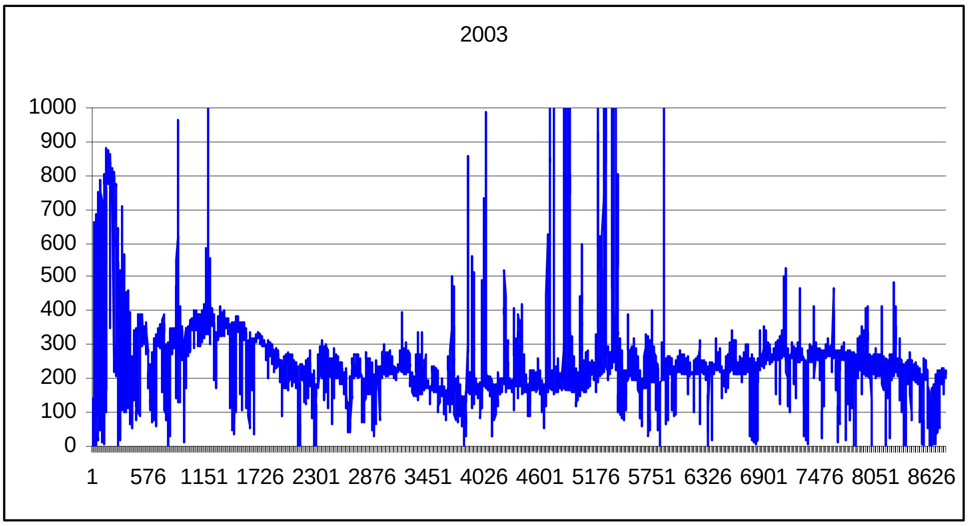


Figure 1: System prices for Western Denmark in 2003

Concerning the natural gas price, Figure 2 shows the development of the German natural gas prices from 1991 until February 2006. For the reference year of 2003, the average annual price is around 92 DK/MWh. For simplicity, and as the price trend increases, it is chosen to use the price of **100 DKK/MWh.**

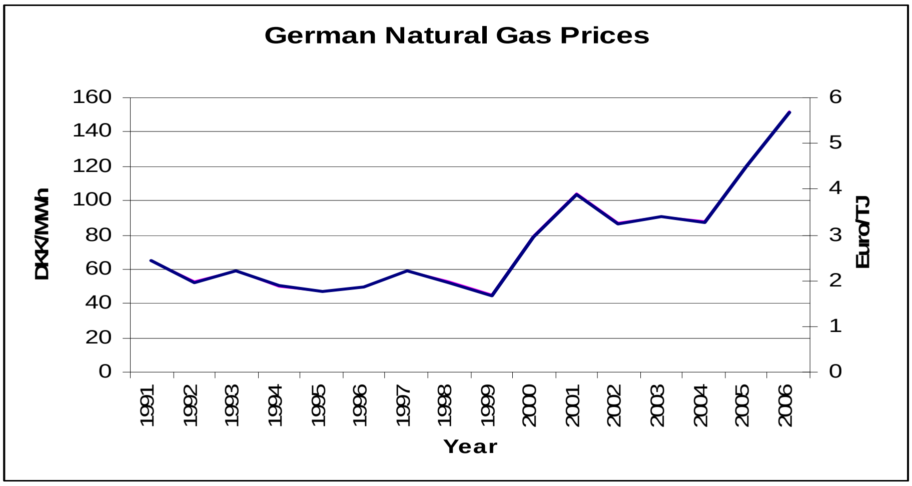


Figure 2: Natural gas prices on the German market until February 2006 as taken from the German Ministry of Economy and Technology.

As for the operational costs, the initial models show an average annual number of start-ups below 1 start/day. For example, at an operational cost of 15 DKK and 40 DKK for the compressor and the turbine, respectively, the EnergyPLAN strategy 2 model results in around 172 start-ups for each unit, whereas the Operational Hour Matching model gives around 225 Start-ups. This allows the use of the lower values of the fixed operational costs found in the PowerStore report.

Hence the assumed operational costs are:

Comp OC = 17 DKK/MWh
Turb OC = 20 DKK/MWh

The values above include both fixed and variable operational costs. Both are per MWh produced since the planned maintenance services (fixed operational costs) depends on the equivalent number of operational hours. The highlight below summarizes the main economic factors assumed.

Economic Factors

Electricity Price Time Series = 2003 DK West Spot Prices
Natural Gas Price = 100 DKK/MWh
Compressor Operational Cost = 17 DKK/MWh
Turbine Operational Cost = 20 DKK/MWh

Theoretical Models – Unlimited Storage (TMUS)

The TMUS are very useful in defining an “upper limit” for the potential profit that a CAES plant can achieve in a given year. The unlimited storage makes the simulation results independent of the price series order pattern, and thus provides a good starting exercise to examine the ideal system behavior. Two main simulation models were developed so far in this category. The models are:

- The Maximum Hour Matching Model
- EnergyPLAN Strategies 1 & 2

The Maximum Hour Matching Model (MHM)

Concept: The MHM model starts by sorting the prices time series into an ascending duration curve. Then for every hour on the “low price” end, the corresponding production hour is chosen as the maximum price hour in the “residual time series”, meaning excluding the hours when the turbine is already operating. The operation stops once the difference between the compression and the residual maximum price is too low to allow economic operation based on the Marginal Production Cost. Figure 3 illustrates this concept, in which the operation can be thought of as the compressor and turbine operational hours starting from the opposite edges of the price series and approaching the center.

Results:

- Production Graphical:

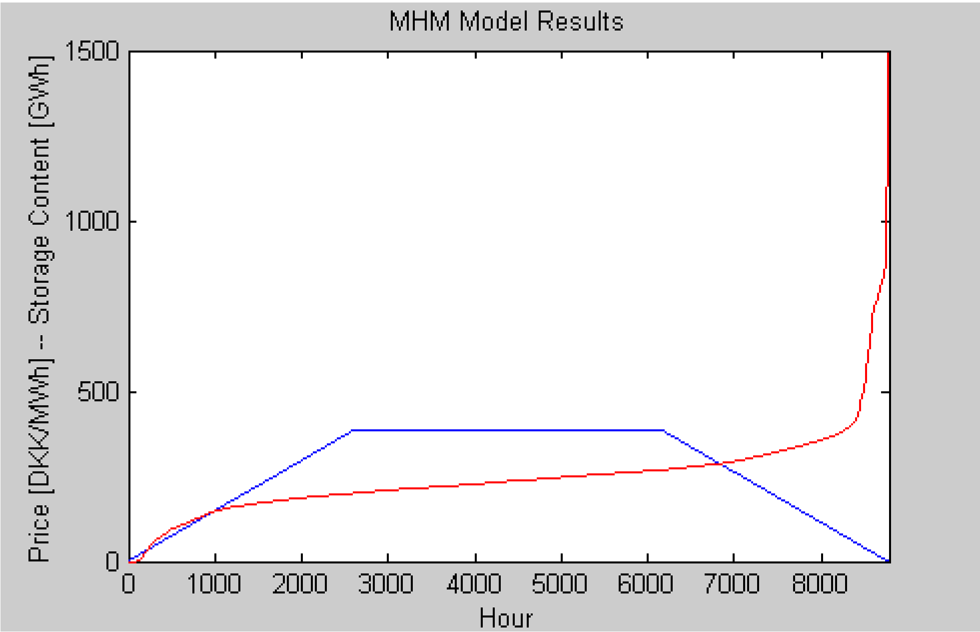


Figure 3: MHM model storage content against the system prices. Note that the maximum price reaches 4430 DKK/MWh (not shown on the graph).

MHM					
Net Income	137.12	M.DKK	Comp Operation	2,607	hours
Min Sales Price	269.01	DKK/MWh	Comp Startup	–	
Max Buying Price	200.30	DKK/MWh	Turb Operation	2,607	hours
El Sales Income	357.26	MDKK	Turb Startup	–	
El Comp Cost	78.61	MDKK	Max Storage	385.51	GWh
Comp OC	9.48	MDKK			
Turbine OC	18.82	MDKK			
Ngas Cost	131.20	MDKK			

Table 1: Main results of the MHM model

Notes and Reflections

- Since the model is based on hour matching, it is important that the compression and expansion rates are equal in terms of air quantity pumped in and out of the storage per operational hours. In other words, the turbine and the compressor must have the same number of operational hours per full charge/discharge cycle.
- It can be shown that, in this model, it is not economic to run the system in the bypass mode during hours when the minimum selling price is lower than the maximum buying price (Figure 4). Hence, the value of the profit found represents the maximum possible profit for a given year in the case of no storage limitation.

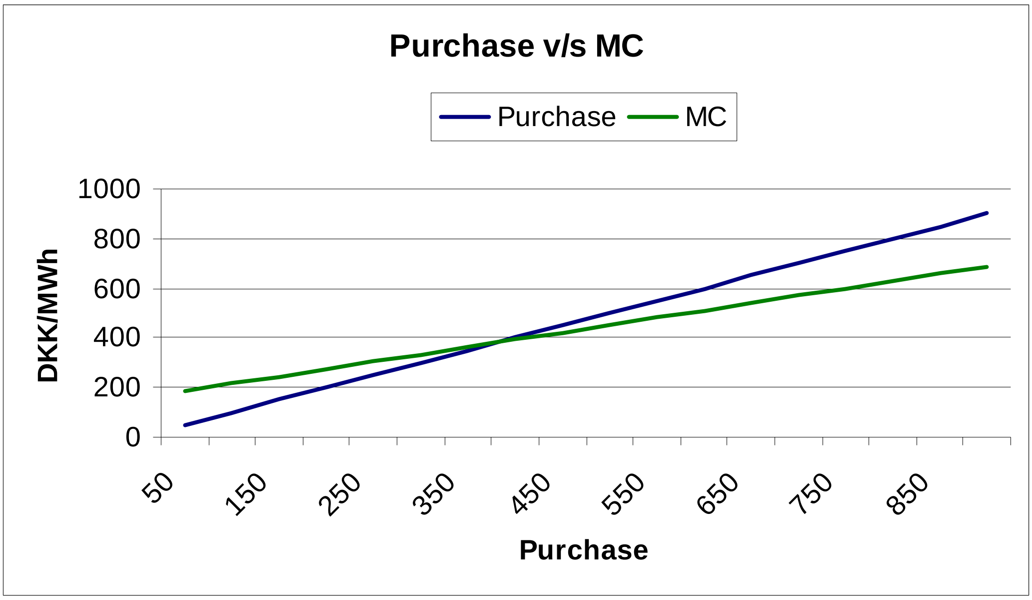


Figure 4: The maximum buying price and the corresponding marginal cost (minimum selling price). Note that for prices above 413 DKK/MWh, it pays to run the compressor and the turbine together in a bypass mode avoiding the storage.

EnergyPLAN Strategies 1 & 2

Concept: The concept in this model is similar to the previous MHM model; however, the price time series here is not sorted. Ideally, this should give the same net profit results compared to the MHM model, especially since start-up costs are not included in the calculation. The EnergyPLAN St.1 & 2 model presents a better starting point for further refinement by adding storage limitation, as would be discussed in the Strategy 3 model.

In Strategy 1, the algorithm consists of starting by a user-defined “minimum selling price”. The turbine would thus operate in all hours with prices above this price. The annual consumption is then calculated. The “maximum buying price” is then increased in a gradual manner until the total annual compression equals the annual consumption. The initial storage content is then adjusted to ensure positive storage content during the total period. The compressor and the turbine are not allowed to operate at the same time.

Strategy 2 performs the same calculation as above; however, it automatically defines the optimum minimum selling price and the corresponding maximum buying price.

Results:

- Production Graphical (from running strategy 2):

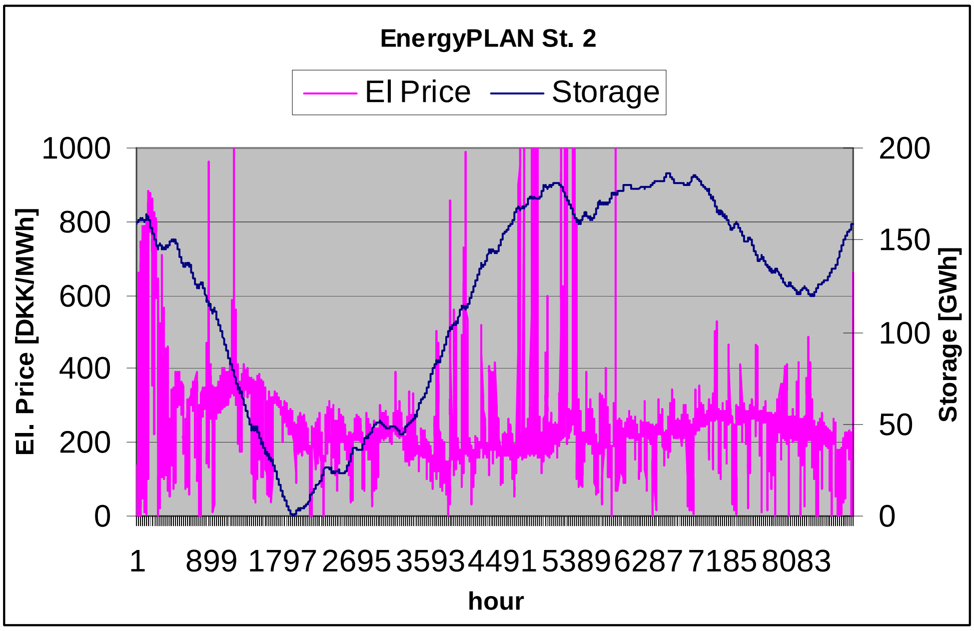


Figure 5: System Prices and corresponding storage from running EnergyPLAN St 2. Note the compressor operates for prices below 204 kr. and the turbine operates for prices above 256 kr.

EnergyPLAN Strategy 2					
Net Income	136.88	M.DKK	Comp Operation	2777	hours
Min Sales Price	265.79	DKK/MWh	Comp Startup	308	Starts
Max Buying Price	204.27	DKK/MWh	Turb Operation	2776	hours
El Sales Income	373.48	MDKK	Turb Startup	270	Starts

El Comp Cost	85.97	MDKK	Max Storage	186.31	GWh
Comp OC	10.10	MDKK			
Turbine OC	20.04	MDKK			
Ngas Cost	120.46	MDKK			

Table 2: Main results of the MHM model

Practical Operational Models (POM)

Practical operational models reflect real life by assuming a limited knowledge about future market prices. Two models fall into this category, EnergyPLAN strategies 4 and 5 (referred to as St. 4 and St. 5). While St. 4 assumes knowledge of the average price for a limited upcoming period, St.5 assumes that the price variation in a preceding period is used as a model for production in an upcoming period.

EnergyPLAN St. 4 model

Concept: The concept behind this model is to take the average price of a coming period and bid on the market correspondingly. The bid on the market occurs in such a way that the price difference between the buying and bidding prices is equally distributed around the average price. Figure 6 demonstrates this concept for a 24-hour period. The middle line represents the price average for the shown 24-hour period. Based on that, the distance to the two other lines is calculated.

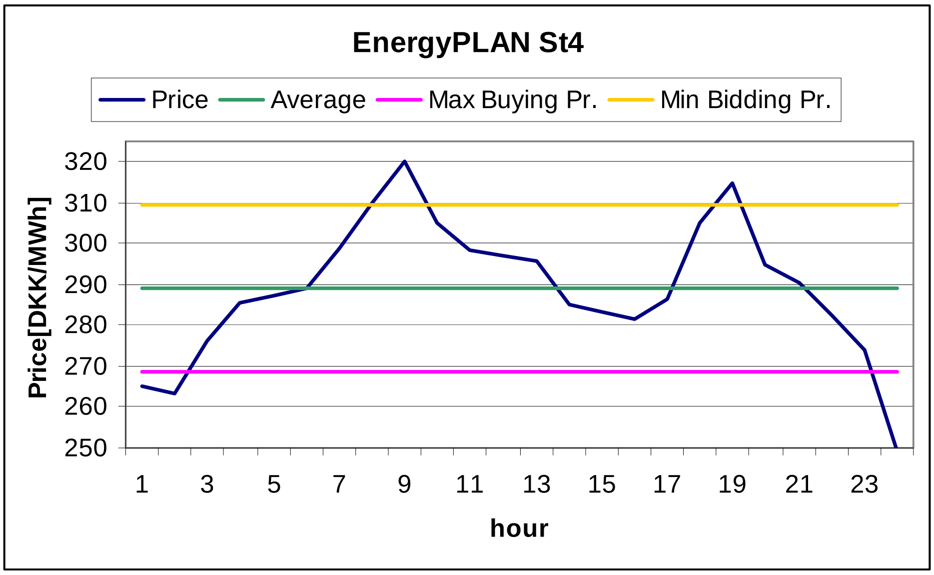


Figure 6: EnergyPLAN St4 concept, where the average of an upcoming period, 24 hours in this figure, is used to calculate the market bidding prices.

The distance between the minimum/maximum lines and the average price can be calculated analytically using the following equation:

$$M.C._{(\bar{P}-\Delta P)} = \bar{P} + \Delta P \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots(1)$$

Where:

- $\bar{P}$ is the average price over the given period
- ΔP is the price difference from the average price
- $M.C._{(\bar{P}-\Delta P)}$ is the marginal cost of production for an electricity unit bought at the price $\bar{P} - \Delta P$

The marginal cost can be expressed as:

$$M.C._{(\bar{P}-\Delta P)} = \frac{[(P - \Delta P) + K]}{\eta_C \eta_T} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots(2)$$

Where

- η_C is the compressor efficiency
- η_T is the turbine storage efficiency defined as the power output per unit storage energy input.
- K is a constant that includes the variable operational costs and fuel costs:

$$K = O.C._C + \eta_C \eta_T \left(F.R. \cdot N.Gas.\mathrm{Pr}ice + O.C._T\right) \ldots\ldots\ldots\ldots(3)$$

  - $O.C._c$ is the compressor operational cost
  - $O.C._T$ is the turbine operational cost
  - $F.R.$ is the fuel ratio

Substituting (2) and (3) in (1) leads to the following relation:

$$\Delta P = \frac{\bar{P}(1 - \eta_C \eta_T) + K}{1 + \eta_C \eta_T} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots(4)$$

Results (for 24-hour period):

- Production Graphical

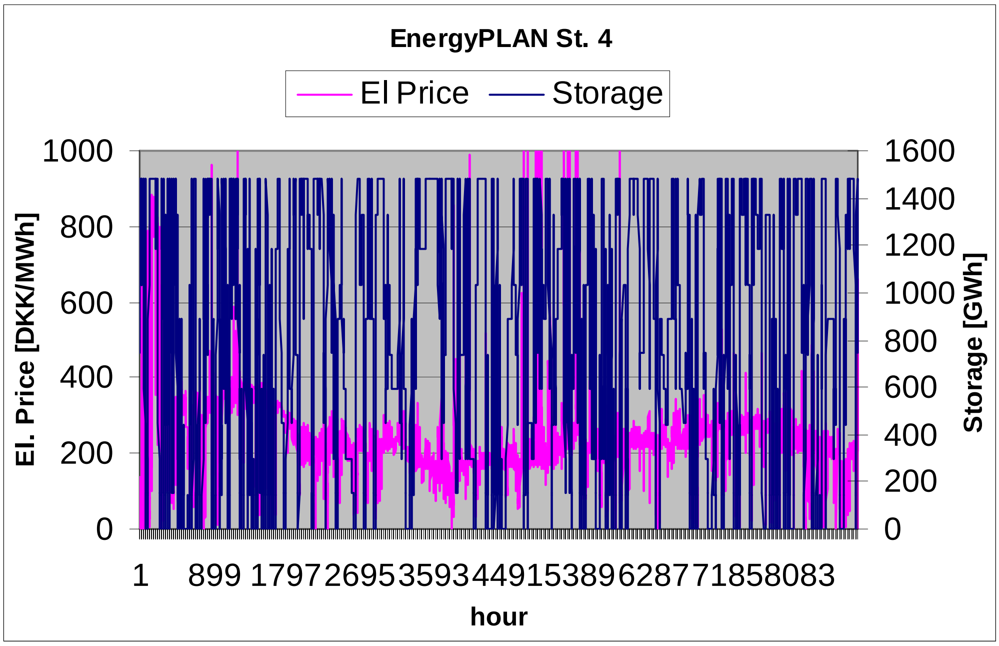


Figure 7: Production graphical for EnergyPLAN St.4 at a forward period of 24 hours.

EnergyPLAN St. 4					
Net Income	72.23	M.DKK	Comp Operation	1395	hours
Min Sales Price	-	DKK/MWh	Comp Startup	317	Starts
Max Buying Price	-	DKK/MWh	Turb Operation	1395	hours
El Sales Income	209.43	MDKK	Turb Startup	323	Starts
El Comp Cost	61.51	MDKK	Max Storage	1.480	GWh
Comp OC	5.08	MDKK			
Turbine OC	10.07	MDKK			
Ngas Cost	60.54	MDKK			

Table 3: Main results of EnergyPLAN St. 4 at a price period of 24 hours.

Notes and Reflections

- It was found that the maximum profit in 2003 can be achieved at a price difference of 20 hours. The results are shown in table 4.

EnergyPLAN St. 4 – 20 hours					
Net Income	73.52	M.DKK	Comp Operation	1525	hours
Min Sales Price	-	DKK/MWh	Comp Startup	331	Starts
Max Buying Price	-	DKK/MWh	Turb Operation	1525	hours
El Sales Income	223.19	MDKK	Turb Startup	331	Starts
El Comp Cost	66.91	MDKK	Max Storage	1.48	GWh
Comp OC	5.55	MDKK			

Turbine OC	11.01	MDKK			
Ngas Cost	66.19	MDKK			

Table 4: Main results of EnergyPLAN St. 4 at a price period of 20 hours.

- For the different years, the maximum profit occurs at different hour periods

	Net Profit [M.DKK]	Hours Period
2000	21.01	18
2001	22.75	20
2002	50.97	14
2003	73.52	20
2004	13.35	17
2005	98.72	15

Table 5: The Hour Periods in which a maximum profit is achieved for the various years.

- The optimum seems unique in the area around the maximum profit hour period; however, in one case in 2005 it was not.

EnergyPLAN St. 5 model

Concept: Strategy 5 is similar to strategy 4 with the difference that strategy 5 utilizes the price average of the previous hours for determining the bidding strategy of the upcoming hours.

Results (for 24-hour period):

- Production Graphical

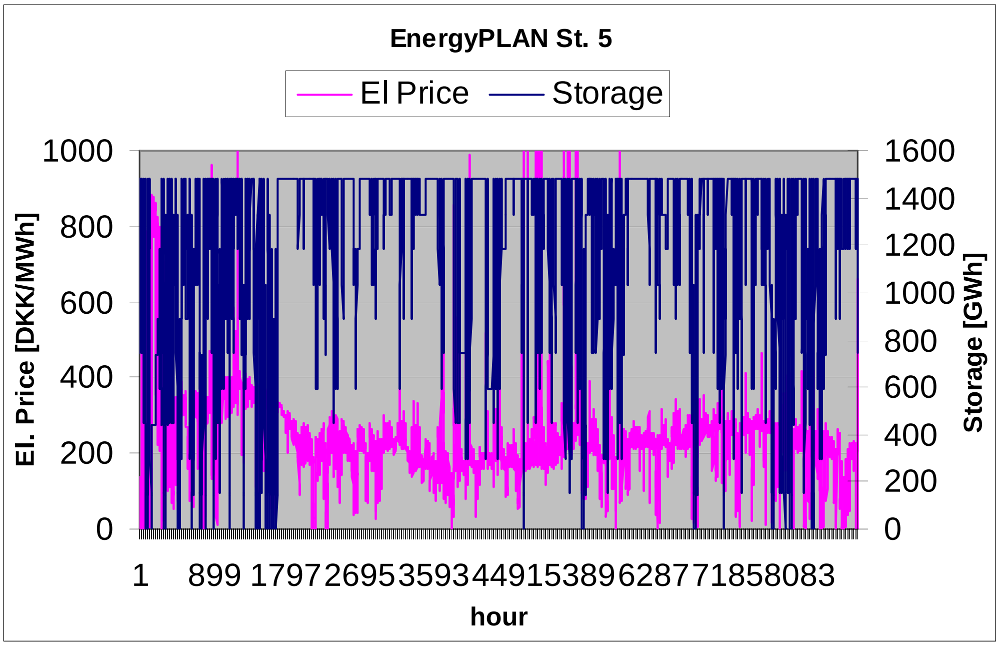


Figure 8: Production graphical for EnergyPLAN St.5 at a forward period of 24 hours.

EnergyPLAN St. 5					
Net Income	66.99	M.DKK	Comp Operation	1366	hours
Min Sales Price	-	DKK/MWh	Comp Startup	320	Starts
Max Buying Price	-	DKK/MWh	Turb Operation	1366	hours
El Sales Income	210.81	MDKK	Turb Startup	330	Starts
El Comp Cost	69.70	MDKK	Max Storage	1.48	GWh
Comp OC	4.97	MDKK			
Turbine OC	9.86	MDKK			
Ngas Cost	59.28	MDKK			

Table 6: Main results of EnergyPLAN St. 5 at a price period of 24 hours.

Notes and Reflections

- The maximum occurs at 21 hours

EnergyPLAN St. 5 – 20 hours					
Net Income	70.27	M.DKK	Comp Operation	1489	hours
Min Sales Price	-	DKK/MWh	Comp Startup	379	Starts
Max Buying Price	-	DKK/MWh	Turb Operation	1489	hours
El Sales Income	223.23	MDKK	Turb Startup	382	Starts

El Comp Cost	72.17	MDKK	Max Storage	1.48	GWh
Comp OC	5.42	MDKK			
Turbine OC	10.75	MDKK			
Ngas Cost	64.61	MDKK			

Table 7: Main results of EnergyPLAN St. 4 at a price period of 20 hours.

- The above-mentioned maximum is not unique. While the profit consistently decreases as the number of hours decreases, the profit fluctuates as the number of hours is increased. For example, the profit at 30 hours is 68.65 MDKK, whereas it is 69.77 MDKK at 50 hours.

.

EnergyPLAN St 4 - trin 1

Concept: Iterate over the hours and produce during the hours when the bypass mode operation is profitable and the storage is empty

Notes: Interesting to try to bypass production also in high price hours with non-empty storage

Theoretical Models – Limited Storage (TMLS)

EnergyPLAN St 4 and 5 - step 1

Concept: The concept is to go back after calculating EnergyPLAN St. 4 or 5 –default and check on the hours when the turbine production can be improved. This is done by starting from the end of the year and looking backwards in steps of 10 hours. If an hour exists within the previous 10 hours with better prices than the last hour in which the turbine is producing, then the turbine is made to produce at full capacity in the hour with higher prices and the increased amount is deducted from the last hour in the 10-hour range.

EnergyPLAN St 4 and 5 – steps 2 - 5

Steps 2-5 continue the iteration after performing the default and step 1 algorithm
<u>Step 2:</u> Improving existing expansion hours

1. Iterate beginning at the end of the year
2. Compare the price of each hour to the prices of its 10 preceding hours (10 due to storage size)
3. If an hour with higher price is found within the 10 hours, the turbine production at the current hour is shifted to the hour with better price based on the available un-utilized turbine capacity

Step 3 is performed after performing the calculations up to Step 2

Step 3: Improving existing compression hours

1. Iterate beginning at the end of the year
2. Compare the price of each hour to the prices of its 10 preceding hours (10 due to storage size)
3. If an hour with a lower price is found within the 10 hours, the compressor production at the current hour is shifted to the hour with lower price based on the available un-utilized compressor capacity

Step 4 is performed after performing the calculations up to Step 3

Step 4: Finding extra operation potential

1. Iterate from the beginning of the year
2. Check for potential compression hours (PCH), with unutilized storage and compressor capacity
3. Check for potential expansion (PEH) hours following the PCH with prices exceeding the MC
4. Increase the compression/expansion up to the maximum capacity, while respecting storage constraint in all intermediate hours

Step 5 is performed after performing the calculations up to Step 4

Step 5:

1. Iterate forward
2. For hours with compressor operation, look forward up to the hour with empty storage
3. Check for turbine operational hour within that range with system price lower than the MC
4. Reduce the compression/expansion in these 2 hours while respecting the storage limit in the intermediate hours

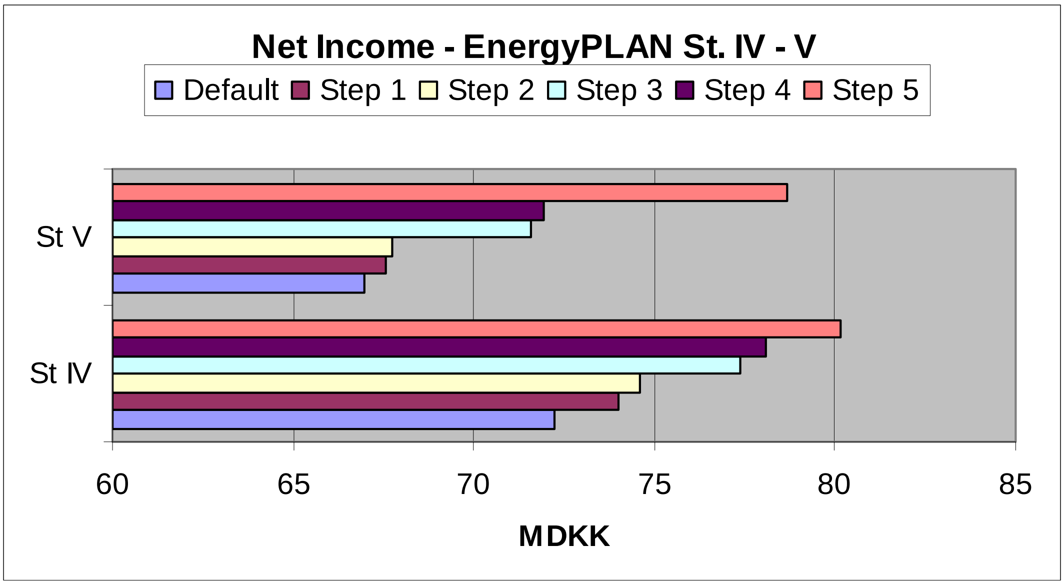


Figure 9: Net Income for EnergyPLAN St. 4 and 5. The results are for a 24-hour period.

EnergyPLAN St 6 and 7

EnergyPLAN strategies 6 and 7 were developed for finding the theoretical optimum operational income of the CAES plant based on a deterministic annual price time series (note the time series consists of 8784 hours thus representing a leap year). The result from these two strategies was slightly higher than the optimum found by the EnergyPRO model following the competition. Below, the algorithms of strategies 6 and 7 are shown followed by the competition result. It is important to note that both strategies were replaced by a more refined strategy 6 that would be explained in Chapter 4.

1	Initialize Variables
2	Identify maximum electricity price in the “Turbine price time series”, then set the price during that hour to -90,000 DKK/MWh in the “Turbine price series” to avoid its re-selection
3	Identify forward storage limitation range from the maximum price forward until the hour where the storage content is less than the compressed energy input to the storage by an hour of full compressor capacity operation
4	Identify backward storage limitation range from the maximum price backwards until the hour where the available storage unused space is less than compressed energy input to the storage by an hour of full compressor capacity operation
5	Identify minimum and second-minimum price in the range determined in [3] & [4]
6	Check the marginal production cost based on compression and expansion during the minimum and maximum price hours found in [2] and [5] respectively. If profitable, continue to [7], otherwise return to [2]
7	Operate the turbine full capacity during the hour found in [2], then compress the same amount of energy used by increasing the compressor operation in the minimum price hour. If the available compressor capacity is not enough, set the price during the minimum price hour in the “compressor price series” to 90,000 DKK/MWh to avoid reselection and continue to [8], otherwise, go to [11]
8	Check profitability of the “second minimum” price hour. If profitable, increase the compressor operation based to compensate for the turbine consumed energy that could not be compressed in step [7]. If the avaliable compressor capacity is enough, go to [11], otherwise, continue to [10]
9	Update turbine operation to match the amount of energy that could be compressed in [7] and[8]
10	update storage, and return to [2]

Strategy 7

1	Calculate Strategy 6
2	Go through the Storage time series and Identify the hour with the minimum available space for extra pumping
3	Move forward form the hour of limited storage identified in [2] till the hour with no available storage space. In this range, identify the hour with maximum price and available turbine production capacity
4	Move backwards from the hour of limited storage identified identified in [2] till the hour with no available storage space. In this range, identify the hour with minimum price and available compressor capacity
5	Determine the minimum among the following three determined variables: 1- Available storage space; 2 – Available turbine production capacity; 3- Available compressor operational capacity
6	Check the marginal production cost. In case the price at the turbine hour is greater than the MC, operate the compressor and turbine in their allocated hours based on the minimum determined in [5] and update the storage,
7	Mark the minimum storage hour to avoid considering it in future iterations
8	Iterate back to step [2] until the iteration limit set by the user is reached
9	Calculate output values (costs, profit, maximum storage content, etc.)

Competition Results

	EnergyPRO	EnergyPLAN St. 6 & 7
Income (electricity)=	248.46	244.93
Cost (electricity)=	73.84	72.06
Pump (operation)	6.12	5.99
Turbine (operation)	12.15	11.89
Ngas	72.99	71.46
Storage diff	0.18	-0.01
Sum =	**83.36**	**83.53**

It is noted here that the EnergyPRO model operates based on dividing the market prices into user-defined "priority levels", where the highest price hours represent the highest production priority. Although the results of this model were similar to those of the EnergyPLAN St. 6 &7, the time consumed ranged around 30 minutes due to the large amount of priority levels that needed to be created, as opposed to a couple of seconds for EnergyPLAN. One of the disadvantages of the EnergyPLAN st. 6 & 7 at this stage, however, was the limitation of optimizing only compressor/turbine capacities that had close amounts of compression/expansion time. This limitation was removed in the updated version presented in Chapter 4.

Comparing the results on an hourly basis, it could be seen that the results revolved around the same optimum solution with minor differences, and a small space for improvement.

Following the competition, Brian presented results of a dynamic optimization that gave the exact same answer as the EnergyPLAN St.6 & 7. The operation of that simulation is not presented here. However, we plan to write an article summarizing the 3 optimization models presented by each of the participants.

The EnergyPLAN simulation was further refined later where both strategies 6 and 7 were combined in one. Further description of the new simulation is found in the EnergyPLAN documentation, see www.EnergyPLAN.eu

Appendiks D

Documentation of the two practical operational strategies and the annual optimum simulation in the EnergyPLAN model (strategies 4,5 and 6)

Documentation of

CAES Market Optimization Strategies in the EnergyPLAN model

Georges Salgi and Henrik Lund 13/06/07

In general, the EnergyPLAN model has a focus on system analysis, i.e., the analysis of national or regional energy systems. However, the model enables the business economic analysis of individual plants in the case of electricity storage systems with a special focus on CAES (Compressed Air Energy Storage) plants.

Three different electricity market operation strategies can be chosen:

- ***Optimal strategy (strategy 6)***, which is based on a deterministic annual time series, and is considered to return the highest possible annual operational profit;
- ***Practical historical strategy (strategy 5)***, in which decisions on buying and selling electricity are solely based on the knowledge of the price average of a certain historical period, e.g., 24 hours;
- ***Practical prognostic strategy (strategy 4)***, in which decisions on buying and selling electricity are based on the average of the coming, e.g., 24 hours. Such a strategy presumes the presence of good price prognosis.

Strategy 6 is thus aimed at finding the "theoretical" optimum operation of the electricity storage plant given the annual electricity price time series. Strategies 4 and 5, on the other hand, reflect a "practical" operational mode with the operator having limited knowledge on future market conditions.

Electricity Storage Input/Output Window

Figure 1 shows a caption of the main electricity storage Input/Output window. To activate such options one has to press the button "Advanced CAES", which can be accessed under the *Input* → *Storage* tabs at the top of the window.

While the upper part of the window is concerned with electrolysers for hydrogen generation, the lower part is specified for electricity storage applications.

The main technical input variables can be filled in the uppermost area marked in red in Figure 1. In order to accommodate storage/generation hybrid technologies such as CAES, the input includes fuel consumption during electricity generation. The main required inputs in this area are:

- Pump/Compressor capacity, where the Pump/Compressor is the term used to represent the technology that converts electric power to stored power, which could also be a recharging battery for example.
- Turbine capacity, where the turbine is the term used to represent the technology that converts stored power to electricity.
- Pump/Compressor efficiency in converting the electric energy to stored energy
- Turbine efficiency in converting stored energy to electric energy. In technologies such as CAES, this efficiency can be greater than 1 due to fuel addition.
- Fuel Ratio, which is the ratio of the fuel energy added per unit electricity produced:

$$Fuel\ Ratio = \frac{Fuel\ input}{Electricity\ output} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots [1]$$

- Storage capacity, which is the net amount of storage capacity in GWh.

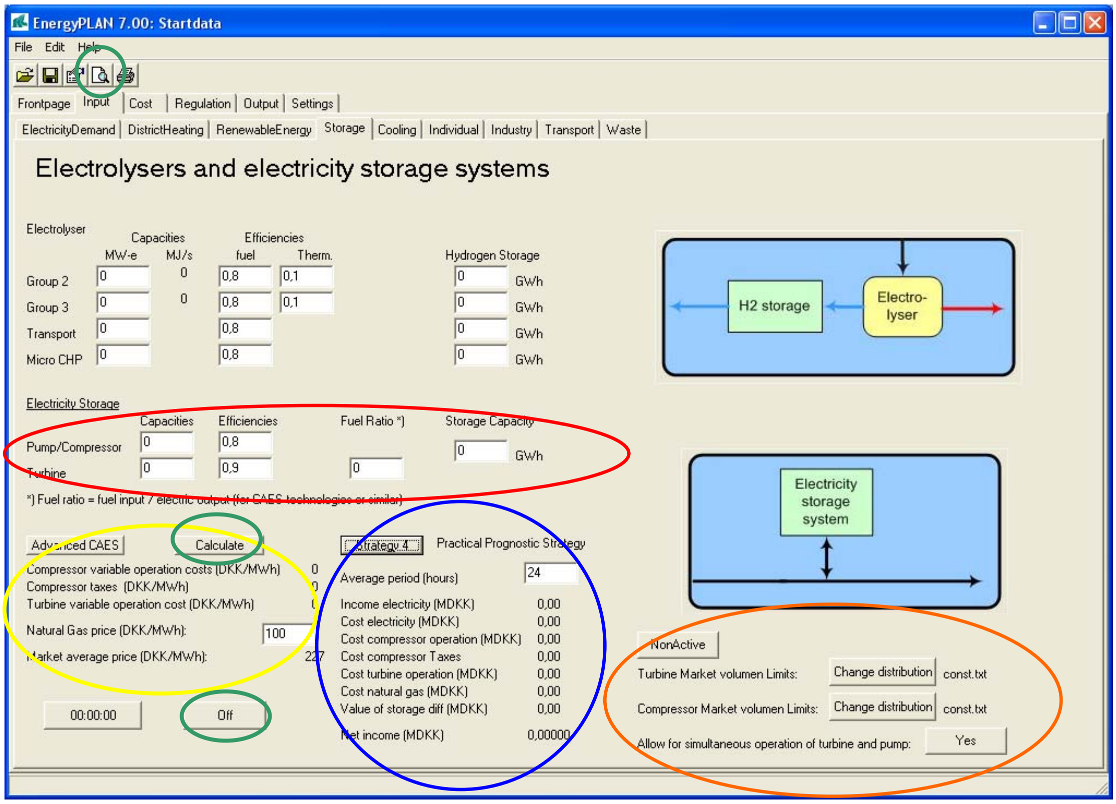


Figure 1: EnergyPLAN electricity storage main Input/Output window

The main financial inputs are shown within the lower-left area marked in yellow. Apart from the fuel cost, the other inputs are carried from other windows. The pump and turbine operational costs reflect the variable entered under the *Cost* → *Operation* tabs, whereas the average electricity price reflects the average of the price time series entered under the *Regulation* tab.

The main output operational results are shown in the lower center of Figure 1 marked in blue. These results include electricity consumption and production costs, operational costs, fuel costs, the net income, and the maximum utilized storage capacity. Besides, certain strategy specific variables are entered in the box on top of this area. For example, the maximum number of iterations in strategy 6 and the projected period in strategy 4 are entered in this area.

To the lower right of the screen (marked in orange in figure 1), the function of simulating regulating power is available. The user can "Activate" this function by clicking on the "Non-Active" button. When active, the user-entered upward and downwards regulating power time series would limit the turbine and compressor operation to the actual regulating power need (as opposed to running only based on prices). This is done to allow for situation where the CAES plant operates only on the regulating power market.

The "Calculate" button runs the simulation of the chosen strategy. For getting the hourly values, activate the "Off" button shown in green in Figure 1 in the lower left corner to "On", then press the "View Clipboard" button shown in green in the top toolbar. For extracting hourly values to the clipboard, (where they can be pasted into a spreadsheet), start by activating the "Off" button. Thereafter select the tabs: Output → Overview, and press the "Clipboard" button in the lower left corner. Note that pressing the "Clipboard" button without the "On" button being activated in the energy storage window would run the socio-economic simulation of the model as opposed to the business economic optimization.

Practical prognostic strategy (strategy 4)

The concept behind this model is to take the average price of an upcoming user-specified period and bid on the market correspondingly. The bid on the market occurs in such way that the price difference between the buying and bidding prices is equally distributed around the average price. Figure 2 demonstrates this concept for a 24-hour period. The middle line represents the price average for the shown 24-hour period. Based on that, the distance to the two other lines is calculated.

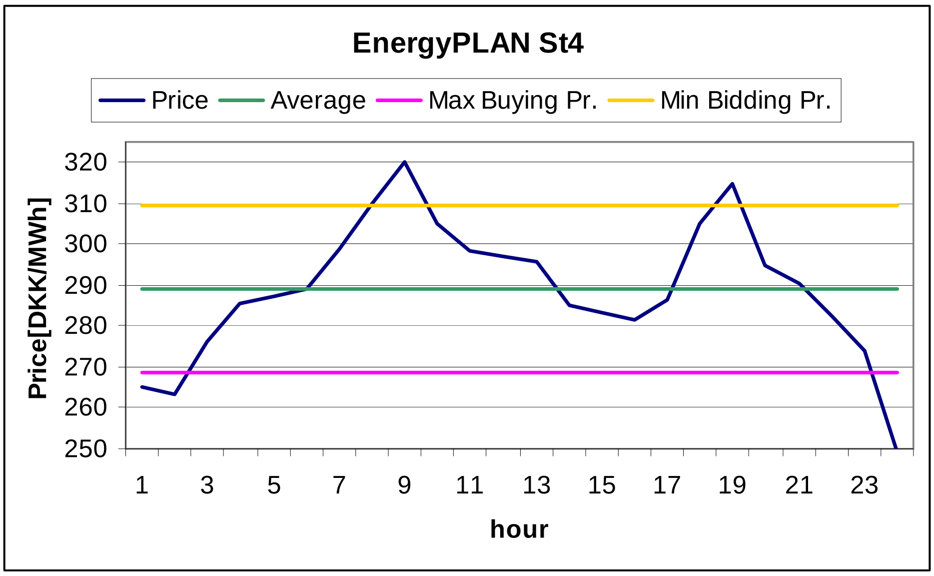


Figure 2: EnergyPLAN St4 concept, where the average of an upcoming period, 24 hours in this figure, is used to calculate the market bidding prices.

The distance between the minimum/maximum lines and the average price can be calculated analytically using the following equation:

$$M.C._{(\bar{P}-\Delta P)} = \bar{P} + \Delta P \;\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots[2]$$

Where:

- $\bar{P}$ is the average price over the given period
- ΔP is the price difference from the average price
- $M.C._{(\bar{P}-\Delta P)}$ is the marginal cost of production for an electricity unit bought at the price $\bar{P} - \Delta P$

The marginal cost can be expressed as:

$$M.C._{(\bar{P}-\Delta P)} = \frac{[(P - \Delta P) + K]}{\eta_C \eta_T} \;\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots[3]$$

Where

- η_C is the compressor efficiency
- η_T is the turbine storage efficiency defined as the power output per unit storage energy input.
- K is a constant that includes the variable operational costs and fuel costs:

$$K = O.C._C + \eta_C \eta_T \left(F.R. \cdot N.Gas.\Pr ice + O.C._T\right) \ldots\ldots\ldots\ldots\ldots\ldots[4]$$

  - $O.C._c$ is the compressor operational cost
  - $O.C._T$ is the turbine operational cost
  - $F.R.$ is the fuel ratio

Substituting (2) and (3) in (1) leads to the following relation:

$$\Delta P = \frac{\bar{P}(1 - \eta_C \eta_T) + K}{1 + \eta_C \eta_T} \;\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots[5]$$

It is noted here that the price average $\bar{P}$ is a moving average and is updated on an hourly basis as opposed to a fixed average over the specified period. This implicitly assumes the ability to update market bids on an hourly basis.

In some hours with very high electricity prices, it sometimes pays to bypass the storage while operating the compressor and turbine at the same time. Such operation is included in the strategy, and allows the compressor and turbine to operate simultaneously during the same hour in case the storage is empty. However, one can deactivate the simultaneous operation option by deactivating the "Yes" button in the lower right corner to "No".

Practical historical strategy (strategy 5)

Strategy 5 is similar to strategy 4 with the difference that strategy 5 takes the price average of user-specified previous periods of hours and uses it as the basis for determining the bidding strategy of the same upcoming period of hours.

Optimal strategy (strategy 6)

Strategy 6 is aimed at finding the maximum theoretical operational income given a deterministic annual electricity price time series. The algorithm can be summarized in 7 main steps:

1) **Identify the maximum electricity price** in the "Turbine prices" time series, which is initialized as a copy of the original electricity prices time series. In this "Turbine prices" time series, hours when the full turbine capacity is operating or when there is no potential profit are given a low negative value in order to avoid their reselection in later iterations.

2) Identify the **storage boundaries around the maximum price.** In this step, the hours before and after the maximum price hour are examined. The first hour in the backward range following an hour with full storage is considered as the "range start", whereas the first hour with an empty storage in the forward range is considered as the "range end". This range constitutes the time space where recharging/discharging is possible. The range can very well constitute only the maximum price hour, in which case the plant would operate in the bypass mode.

3) Identify the **minimum electricity price** within the range defined in step 2.

4) Calculate the **marginal operating cost (MC)** based on the minimum price found in step 3. The MC is calculated according to equation [3] presented in Strategy 4 where (P- ΔP) is replaced by the minimum electricity price. If the maximum electricity price found in step 1 is greater than the MC, the calculation proceeds to step 5, otherwise, the price in the "Turbine prices" time series is set to a low negative value to avoid its re-selection.

5) Determine the **"operation bottle-neck"** in the range between the maximum and minimum prices. This bottle neck is the minimum of the following 3 main variables:

    a. Available unutilized turbine capacity at the maximum price hour
    b. Available unutilized pump capacity at the minimum price hour
    c. Storage bottle neck which is:
        i. The minimum free storage space in case the pumping hour lies before the turbine hour
        ii. The minimum storage content in case the pumping hour lies after the turbine hour.

6) Operate the turbine in the hour of maximum price and the compressor in the hour of minimum price by capacity determined in step 5 and update the storage content. In case the turbine has reached its full capacity at the mentioned hour, set the price in the “Turbine prices” series to a low negative value to avoid its reselection. In case the pump has reached its full capacity, set the hour price in the “Compressor prices” time series to a high positive value to avoid its reselection.

7) Iterate back to step 1 until the iteration limit is reached

To illustrate the algorithm of strategy 6, an example is presented below for a CAES plant with the characteristics summarized in Table 1. An important characteristic of the system in this example is that the rates of air compression and expansion are equal. This allows an equal number of compression and expansion hours, and is presented here for illustration purposes. The Algorithm is, however, capable of dealing with unequal compression and expansion rates.

Table 1: CAES plant characteristics for the illustration example

Compressor	Capacity	216	MW
	Efficiency	0.684259	-
Storage	Capacity	1478	MWh
Turbine	Capacity	360	MW
	Efficiency	2.435724	-
	Fuel Ratio	1.155556	-

Figure 3 shows the NordPool 2005 electricity prices used in the simulation alone with the CAES plant operation at various simulation iterations. After the first iteration, it is seen that the maximum price is identified around hour 4000, and the turbine is operated during that hour. The compressor is operated in the minimum price hour (in this case hour 32) within the time range that does not violate the storage constraint (in this case all hours before the hour 4000).

After 18 iterations, the turbine operates during the 18 hours with the highest prices, while the compressor operates at the 18 hours with the lowest prices. In the case of year 2005, it happens that the low price hours are concentrated at the beginning of the year.

After 100 iterations, the CAES plant operation is more spread across the year as the price maximums and minimums are utilized. Note the correlation between the operation hours and the electricity prices at the top of the figure. The simulation continues until all hours with feasible operation prices are utilized.

Extra note on the Results comparison with DTU

It is finally noted that the results of the updated EnergyPLAN strategy6 were aligned with the results of an updated reference technical scenario from DTU for the year 2003, and the hourly turbine/compressor operation matched exactly, which supports the conclusion that this solution represents the optimum operational income possible given a deterministic price time series.

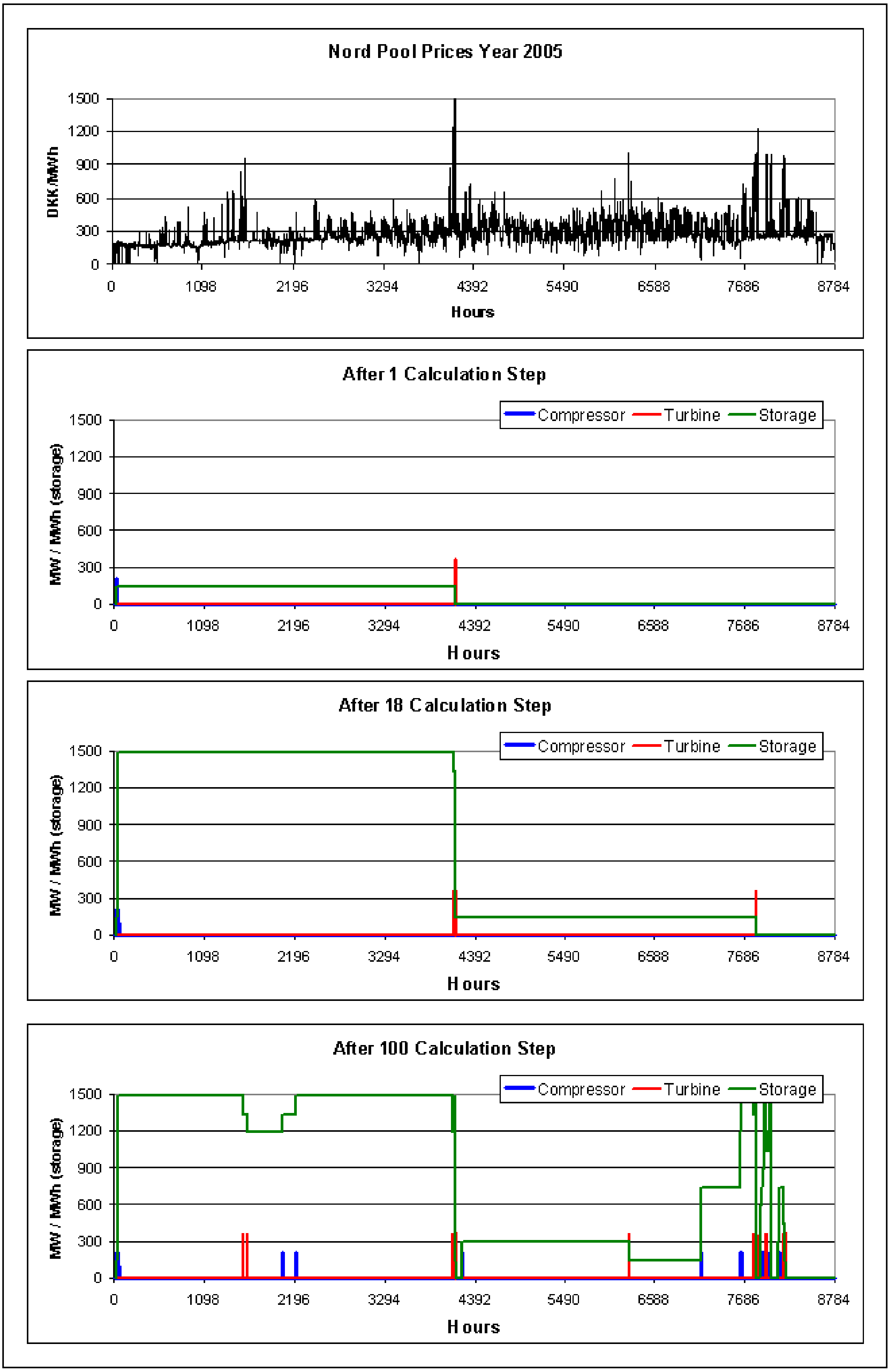
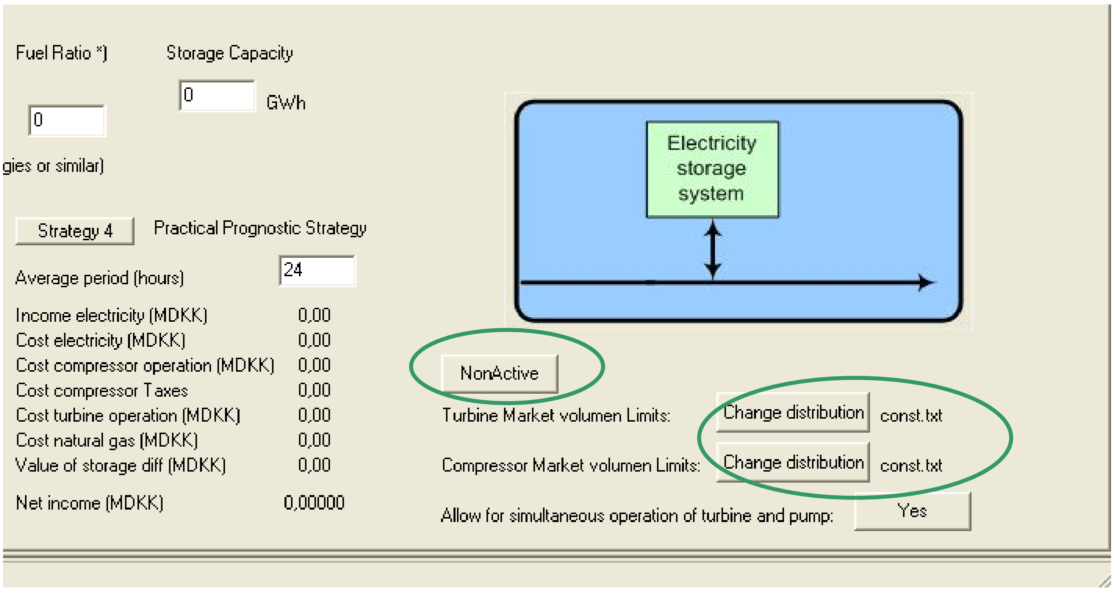


Figure 3: NordPool electricity prices for 2005 and CAES plant operation after various iterations in the strategy 6 algorithm.

Market restrictions (E.g. Regulating Power markets)

All the three described simulation strategies can be used for simulating operation on the regulating power market as well as on the spot market. One just has to specify the hour-by-hour price of the electricity market to operate at. However, in the case of the regulating power market, the market may be limited in size. Such limitation is likely to change from one hour to another. Moreover, the downward limitations are not the same as the upward limitations. Consequently, the EnergyPLAN model enables the specification of such hourly limitations for each market.

To activate this function one has to specify the hourly distribution for each market and to press the “NonActive” button to change it into “Active”. Attention should be given here to whether simultaneous operation should be allowed or not as this reduces the available turbine capacity for upward regulation.



If the regulating power function is kept inactive, the simulations would optimize the plant’s behavior based on electricity prices only. When activated the plant’s compressor and turbine capacities are limited by the actual upward and downward regulation needs. This is illustrated in Figure 4 and 5, where a plant of the same characteristics as the one in Table 1 is operated based on regulating market prices. In figure 4, the simultaneous operation of compressor and turbine IS allowed, and in figure 5, such operation IS NOT allowed.

The variations of the regulating power market prices are shown in the first top figure of both diagrams. The second and third figures show that the Compressor and Turbine operations are limited by the historical regulating power demand. In figure 4, the compressor does operate in 2 hours where there is no down regulation demand. This is due to the relatively high prices that occur at a time where the storage is empty, which allows the plant to operate as a normal gas turbine. However, in figure 5, such simultaneous operation is deactivated. The bottom graph illustrates that the storage content remains within limitation during the mentioned period.

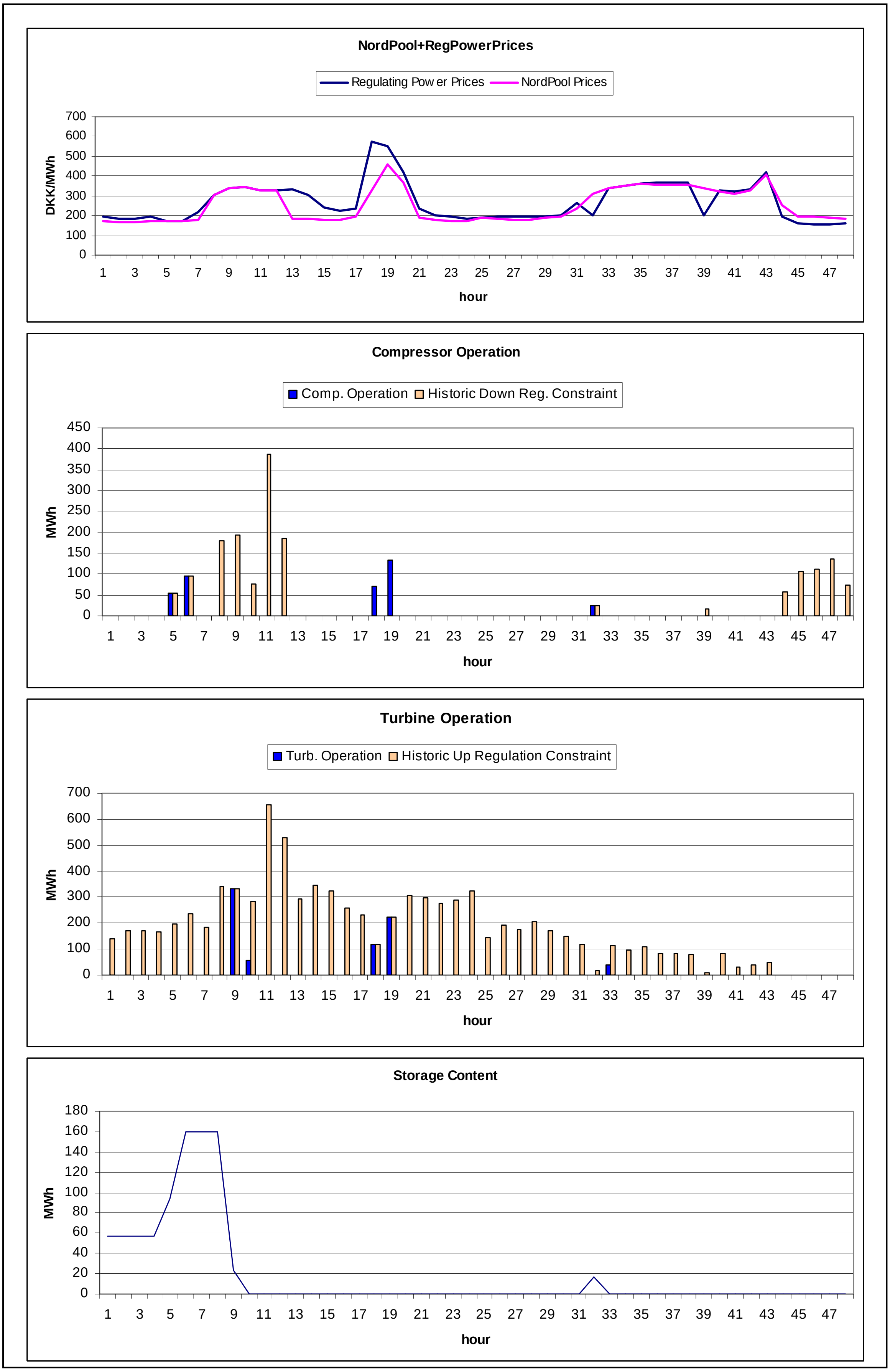


Figure 4: Illustration of the regulating power market function in CAES: a simulation of the 16-17 February, 2005 operating on the Practical Prognostic Strategy (4) where simultaneous compressor/turbine operation IS allowed.

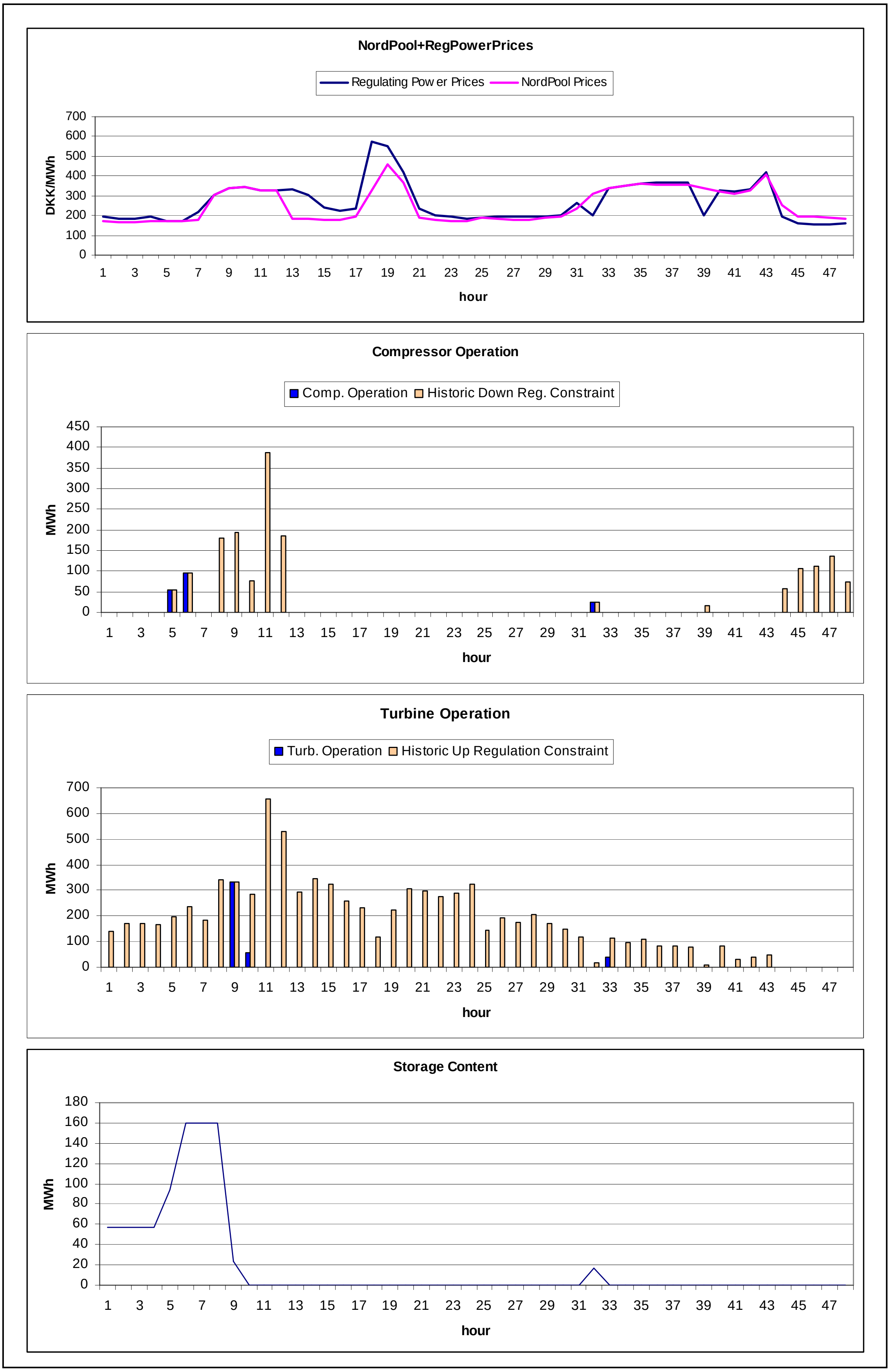


Figure 5: Illustration of the regulating power market function in CAES: a simulation of the 16-17 February, 2005 operating on the Practical Prognostic Strategy (4) where simultaneous compressor/turbine operation IS NOT allowed..

Appendiks E

Excerpt from the article:

“Relocation Technologies for Integration of Fluctuating Renewable Energy Sources”

B.V.Mathiesen and Henrik Lund

Relocation technologies for integration of fluctuating renewable energy sources

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A. Capacities, efficiencies and cost estimates used in the analyses

The alternatives are analysed for comparable capacities which are listed in table 1. For technologies used in combination with CHP an electricity demand of 450 MW has been added i.e. alternatives 1-4. For the transport technologies the 450 MW effect has been used to identify the amounts of vehicles. The flexible demand alternative is comparable to the other alternatives in the sense that the amount of flexible electricity corresponds to decreasing the peak electricity demand with app. 450 MW.

In alternatives 3 250 MW-e of the electrolysers are placed at central CHP units and power plants (PP) and 200 MW-e at decentralised CHP units. The hydrogen storages for CHP units and micro CHP can store more than one month of hydrogen production from the electrolysers. The capacity of the electrolysers for HFCV corresponds to 50% operation time. In the hydrogen storage in this alternative three month of the yearly hydrogen demand for the HFCV or two month of hydrogen production can be stored.

The exchange capability in the BEV alternative is limited in the sense that only 70% of the parked cars are grid connected. Also it is limited by the batteries which can store equivalent to six hours of driving and that only half the battery capacity is available for discharge.

Table 1

Alternatives	**Capacities**		**Efficiencies**			**Cost in MDKK**		**Costs in M€**		**Lifetime (years)**	**O&M costs/year**	**Total annual cost in M€**	**Ref.**
			el.	th./COP	fuel								
1 - EB	450	MWe	-	100%	-	1,0	/MWe	0,1	/MWe	20	1%	4,6	-
2 - HP	450	MWe	-	350%	-	16,3	/MWe	2,2	/MWe	20	1%	75,3	[1]
3 - ELT/CHP													
Electrol.	450	MWe	95%	10%	80%	1,9	/MWe	0,2	/MWe	20	3%	10,8	[2]
H2-storage	300	GWh	-	-	95%	0,4	/GWh	0,1	/GWh	25	0%	1,0	[3]
4 - ELT/micro													
Electrol.	450	MWe	95%		80%	1,9	/MWe	0,2	/MWe	20	3%	10,8	[4]
H2-storage	300	GWh	-	-	95%	0,4	/GWh	0,1	/GWh	25	0%	1,0	[5]
microCHP	220	MWe	45%	45%		14,0	/MWe	1,9	/MWe	20	6%	52,2	[6]
5 - HFCV													
Electrol.	70	MWe	95%	-	80%	1,9	/MWe	0,2	/MWe	20	3%	1,7	[7]
H2-storage	112	GWh	-	-	95%	0,4	/GWh	0,1	/GWh	25	0%	0,4	[8]
Vehicels	450	MWe	-	-	50%	8,9	/MWe	1,2	/MWe	15	0%	44,7	[9]
6 – BEV	450 /225 2,7	MWe drive train MWe to grid GWh	95%	-	90%	14,4	/MWe dr. train	1,9	/MWe dr. train	15	0%	72,4	[10]
7 - 5%FLEX	2,45	TWh	-	-	-	150,0	/TWh	20,0	/TWh	20	1%	3,3	[11]

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The efficiencies of the technologies in the reference system are well documented, as it consists of well developed technologies. Here the efficiencies used in the seven alternatives are presented. Electrolysers are commercially available with app. 60% electricity to fuel efficiency, but more than 80% efficiency may eventually be possible [12-15]. The efficiency of hydrogen storage devices is between 88% and 95% [16]. Here 80% electricity to fuel efficiency and 10% thermal efficiency is used. 5% losses are assumed in the hydrogen storage and in the inverters. The micro CHP units consist of solid oxide fuel cells. Both the electric and thermal efficiency is 45% in the analysis here, although the efficiency may eventually be higher for other applications than micro CHP.

Today efficiencies of more than 60% can also be achieved in fuel cell systems for vehicles and efficiencies of more than 50% are considered possible taking into account, losses because of mass, drag, friction, drive train and electricity consumption for other services than the electric engine, such as lights, cooling etc. This is also the case when losses due to differences because of standard driving patterns have been taking to account. [17;18]. Here the efficiency of HFCV is 50%. These vehicles replace ICE with an average efficiency of 20% in 2030. For BEV an efficiency of 90% is assumed and 5% losses in inverters both in charging and discharging to grid. The maximum capacity of the HFCV is 18 kW and 10 kW for BEV. The HFCV alternative can replace 1% of the vehicle fleet assuming 2.5 mil. vehicles in 2030 and a total drive train capacity of 450 MW. With equivalent assumptions for BEV 1.8% can be replaced. Using the efficiencies for these vehicles above and a future efficiency of exciting cars of 20% the total amount of petrol saved has been calculated for both transport alternatives.

A 3.5 coefficient of performance (COP) of heat pumps is used as an annual average when taking the potential heat sources into consideration. It is assumed that the heat pumps are only able to supply 50% of the heat demand, because the temperatures may prove lower than required. In the model boilers or CHP units have to supply the rest of the heat demand. This COP and limitation may however prove rather conservative as the heat pumps can be combined with heat from flue gas, intercoolers or waste heat from gas engines and turbines thus increasing the COP. Already today the COP has been proven to be higher. It is expected that the COP in the future may be 5-6. The heat storages in the energy system can store heat for fourteen days. The capacities of the heat storage in the reference and in the analysis are comparable to today's capacities.

The efficiencies and costs for technologies in 2030 are derived from [19] and [20]. Here the costs that have been adjusted are elaborated. The costs of EB are based on initial Danish experiences. For larger EB between 8-15 MWe the cost the costs is 4-6 MDKK. The cost of grid connecting these EB is 2-8 MDKK, because of different locations and local grid connection possibilities. The costs of EB is estimated to be 0.5 MDKK/MWe EB and 0.5 MDKK/MW grid connection. The costs of HFCV is 100% more than a normal vehicle. The costs of BEV is 80% more. The cost of a regular vehicle is app. 10,500 € (~ 80,000 DKK). In [21] the costs of electrolysers are estimated to be 0.18 M€/MW in 2030. Here 0.5 MDKK/MW in grid connection cost is added to the costs of electrolysers and to the costs of HP.

The costs of flexible demand is rather hard to determine. Here the costs in the Energy Plan in [22] is used. The costs are estimated to be 500 MDKK for 10% of the electricity demand or 3.3 TWh with a lifetime of 20 years and 1% for operation and maintenance (O&M). In the analysis here this is equivalent to 20 M€/TWh. With 5% flexible demand and taking the amount of meterinstallations into account the investment equivalents to 2500 DKK/installation. Flexible demand can however be introduced in other ways than improving the meters at households and companies.

In table 1 the total annual costs of the difference technologies are calculated from the capacities investment and O&M costs. A real interest rate of 3% is used. The costs of the technologies is used to identify the least cost alternative.

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