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DEMAND-SIDE RESPONSE AS SOURCE FOR FLEXIBILITY

TARBIMISE JUHTIMINE ELEKTRI-SÜSTEEMI PAINDLIKKUSE TAGAJANA

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Elering juhib Eesti elektri ja gaasi ülekandesüsteemi eesmärgiga kindlustada Eesti tarbijatele igal ajahetkel kvaliteetne energiavarustus.

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Eestikeelne kokkuvõte

Projekti eesmärgid

Eleringi tellimusel viisid Pöyry Management Consulting ja PPA Energy läbi uuringu selgitamaks turuosaliste jaoks välja, milline võiks olla tarbimise juhtimise (*demand-side response – DSR)* roll ja väärtus Eesti elektrisüsteemis lähiaastatel ja 2030. aasta perspektiivis. Peamised uurimisülesanded olid:

- DSR-i väärtusootuste defineerimine Eesti turuosalistega läbi viidud arutelude tulemusena;
- Eesti jaoks olulise rahvusvahelise DSR-i kogemuse ülevaatamine;
- Eestile kõige paremini sobivate DSR-i lahenduste kindlakstegemine väärtusootustest lähtuvalt;
- Eestile kõige paremini sobivate DSR-i lahenduste kvantitatiivanalüüs;
- soovitused DSR-i arendamiseks Eestis keskpikas ja pikas perspektiivis.

Eestile sobilikud DSR-i lahendused ja nende väärtus

DSR-i väärtus Eesti elektrisüsteemile suureneb aja jooksul. Samas varieerub DSR-i väärtuse kasv sõltuvalt selle kasutamisest erinevate turuosaliste poolt. DSR-i konkureerivad kasutusviisid hõlmavad:

- hulgiturul kauplemist vältimaks hinna volatiilsust;
- investeeringute edasi lükkamist jaotusvõrkudes; ja/või
- süsteemiteenuste pakkumist riiklikul tasandil aastaks 2025, kui plaanikohaselt peaks toimuma desünkroniseerimine IPS/UPS elektrisüsteemist.

Nendel teenustel on läbi aja erinevad väärtustasemed ning erinevates oludes töötavad need kas üksteisele vastu või täiendavad üksteist. DSR-i sotsiaalmajanduslikku väärtust Eesti süsteemile saab liigitada riikliku tasandi kasudeks (sääst tulenevalt DSR-i kasutamisest hulgiturul, s.t. päev-ette turul, päevasisesel turul ja reguleerimisturul; süsteemiteenuste osutamiseks ja varustuskindlustuse tagamiseks) ning kohaliku tasandi kasudeks (sääst tulenevalt DSR-i kasutamisest kohalike jaotusvõrguprobleemide leevendamiseks või kõrvaldamiseks).

> Lühikeses perspektiivis on DSR-i kasud riiklikul tasandil tagasihoidlikud, kuid need suurenevad järsult pärast 2025. aastat, kui plaanikohaselt peaks aset leidma desünkroniseerimine ja Eesti vajab täiendavaid reserve.

- Ehkki DSR-i saaks kasutada Eestis päev-ette turu kulude optimeerimiseks, on sel eesmärgil tarbimise juhtimisega kaasnev väärtus algselt madal. Modelleerimise tulemused näitavad, et DSR-i hulgituruga seonduv väärtus kasvab ajas ning kasud on ligikaudu 0,5 miljonit eurot 2020. aastal, üks miljon eurot 2025. aastal ja kolm miljonit eurot 2030. aastal. Madal väärtus tuleneb Eesti turu ühendatusest Põhjamaade elektrisüsteemiga, mis on paindlik, ning kus seetõttu on hinnakõikumised väiksed.

- DSR-i kasutamine päevasisesel või reguleerimisturul suureneb tuuleenergia kasvava osatähtsuse tõttu, kuid seda vaid piiratud mahus, tulenevalt naabruses olevate Põhjamaade elektrisüsteemi paindlikkusest (põhineb eeldusel, et leitakse efektiivsed võimalused paindlikkuse jagamiseks ülepiiriliste ühenduste kaudu ka päevasisesel ja reguleerimisturul). See tähendab, et Eesti enda tootjate ja DSR-i turumaht jääb tulevikus eeldatavalt samaks (34 GWh ülesreguleerimist ja 65 GWh allareguleerimist 2014. aastal ja 111 GWh päevasisesel turul). Kui DSR on konkurentsivõimelise hinnaga (madalam praegustest hinnapakkumistest ja naaberriikide pakkumistest) ning kättesaadav, siis on sellel potentsiaali reguleerimisturul tulu teenida. Reguleerimisturu suurus oli 2014. aastal 3,8 miljonit eurot.

- Kui peaks teostuma plaan lahutada Eesti ja Baltikumi elektrisüsteem IPS/UPS sünkroonalast, siis peavad riigil olema oma reservid. DSR-il võib potentsiaalselt olla võtmeroll reservide pakkumisel ning anda Eesti elektrisüsteemile märkimisväärse kulude kokkuhoiu potentsiaali. Loodav väärtus DSR-i kasutamisega reservide hoidmiseks on suhteliselt kõrge, eriti võrreldes DSR-i (vähese) kasutamisega hulgiturul. Kui DSR saab osaleda reservide pakkumisel, siis modelleerimise tulemused näitavad, et keskmine reservide hoidmise hind on ~6,5 €/MW/tunnis ja prognoositav DSR-i aastane turuväärtus reservide pakkumisest on 14,4 miljonit eurot (2030. aastal). DSR-i väärtus seisneb selles, et see vähendab vajadust hoida Eesti elektrijaamasid töös osalise koormusega ja/või vähendab investeeringuid jaamadesse reservide hoidmise eesmärgil. Samuti vähendab see Eesti CO2 emissioone (võrreldes olukorraga, kus DSR ei ole kättesaadav). Kui DSR ei oleks võimeline reserve pakkuma, siis oleks reservide pakkumiseks vaja täiendavaid tootmisvõimsusi. DSR-i poolt asendatava investeeringu täpne suurus on üsna ebakindel: modelleerimine näitab, et vajalike reservide tagamiseks oleks täiendav 125 MW tootmisüksus piisav koos olemasolevate elektrijaamadega. Selleks vajalik investeering moodustaks ligikaudu poole Kiisa 250 MW võimsusega avariireservelektrijaama ehituskuludest ehk umbes 68 miljonit eurot (projekti kogumaksumus oli ligikaudu 135 miljonit eurot). Siinkohal on oluline märkida, et see arvutus põhineb eeldusel, et Eesti peab kõik reservid tagama siseriiklikest allikatest. Kui reserve saaks hankida naaberturgudelt, siis võib see vähendada reservide hoidmisega seonduvat DSR-i koguväärtust ning seda tuleks uurida täiendavalt.

- DSR parandaks märkimisväärselt Eesti varustuskindlustust, kompenseerides väheneva baastootmisvõimsuse ja suureneva tarbimise. Eriti väärtuslik oleks DSR selles osas 2025. aasta perspektiivis, kui Eesti oma tootmisvõimsustest jääb tipukoormuse katmiseks 200 MW ulatuses puudu. Euroopa Komisjoni eestvedamisel on trendiks liikuda varustuskindlustuse osas regionaalse käsitluse suunas. Näiteks teatis energialiidu paketi kohta (COM/2015/0080) kutsub üles rakendama elektri- ja gaasiturgudel regionaalsemat lähenemist varustuskindlusele. Selle valguses kirjutasid kaksteist Euroopa riiki hiljuti alla varustuskindluse regionaalse koostöö deklaratsioonile Euroopa energiaturu raamistikus. Regionaalse vaate kohaldamine varustuskindluse analüüsile näitab, et Eesti DSR-il ei ole tähenduslikku mõju varustuskindluse varule regioonis. Eleringi varustuskindluse aruande kohaselt võib N-1-1 situatsioonis võimsustest puudu jääda, mis tähendab, et 10-15 aasta perspektiivis võib tekkida vajadus täiendava DSR-i või tootmisvõimsuse järele, et planeerimata katkestustega toime tulla.

Kokkuvõttes võib öelda, et peamine väärtus riiklikul tasandil tuleneb vajadusest põhivõrguettevõtja (*transmission system operator – TSO*) reserviteenuste järele, mis kaasneb kavandatud desünkroniseerimisega IPS/UPS süsteemist. See on planeeritud aastaks 2025, ehkki testimise eesmärgil tuleb reservide valmisolek tagada mõned aastad enne seda.

Kohaliku tasandi kasud jaotusvõrguettevõtjale (distribution system operator – DSO) võivad olla kättesaadavad lähiajal (olenevalt DSO plaanist alajaamade tugevdamiseks ja DSR-i kättesaadavusest), kuid investeeringute edasilükkamise seisukohast on need suhteliselt tagasihoidlikud.

DSR võib Eesti jaotusvõrgule väärtust pakkuda võrgu ülekoormuse vähendamise ja võrguinvesteeringute edasilükkamise teel. See väärtus on siiski suhteliselt madal võrreldes väärtusega, mille toob DSR-i kasutamine riiklikul tasandil.

- Kui DSR-i kättesaadavus ning selle odavus ja töökindlus on DSO-le tagatud, siis on olemas potentsiaal DSR-i kasutamiseks madalama võimsuse ja odavama jaotusvõrgu eesmärgil. DSO kokkuhoid DSR-i kasutamisest (vältimaks investeeringuid võrgu tugevdamisse) on hinnanguliselt ligikaudu 0,5-0,7 miljonit eurot aastas.

- DSR-i kasutusmäärad DSO poolt on madalad, eriti kahe trafoga alajaamade puhul, ning kontsentreeritud talvisele tipuajale, mis tähendab, et DSR-il on potentsiaal pakkuda teenuseid üheaegselt nii DSO-le kui ka riiklikul tasandil.

DSR-il on väljavaadet tuua kasu erinevatele Eesti turuosalistele, kuid potentsiaalselt konkureerivateks kasutusviisideks. Kuna kasud ei jaotu ühtlaselt, siis on vaja luua raamistik, mis võimaldaks DSR-i kulusid efektiivselt erinevate turuosaliste vahel ära jagada. Samuti tuleb tähelepanu pöörata konkureerivate kasutusviiside probleemile ning vajadusele kasutada DSR-i seal, kus see kõige rohkem väärtust loob.

- Alajaamade arv, kus DSR-i rakendamine järgmisel aastakümnel kõne alla võib tulla, on piiratud (<10% alajaamade koguarvust). Kättesaadavad andmed ei võimalda määrata, kas investeeringud selliste alajaamade rekonstrueerimiseks tuleks teha pigem varem või hiljem, kuid DSR-i rakendamine (potentsiaali olemasolul) tuleb kõne alla koheselt, kui vastavat alajaama hakatakse rekonstrueerima. Mõned neist võivad olla potentsiaalsed DSR-i pilootprojektid.

- Mõnes kohas võib DSO jaoks olla majanduslikult põhjendatud rakendada DSR-i ainult jaotusvõrgu jaoks.

- Näib, et kõige rohkem on DSR-ist kasu riiklikul tasandil seoses reservide pakkumisega. DSO jaoks näib kasu olevat piiratud. Eelnevate uuringute tulemuste põhjal on märkimisväärne osa (>60%) DSR-i potentsiaalist (mahust) jaotusvõrgus (elumajad, kontorid).

- Arvutused näitavad, et märkimisväärse majandusliku kasu saavutamiseks tuleb enamiku DSO lahenduste korral DSR-i kasutamist jagada (hulgiturul või reservidesse). Sellisel juhul toob see kaasa märkimisväärse kokkuhoiu DSO võrguinvesteeringute pealt. Antud protsessi toetamiseks peavad paigas olema vastavad jagamisskeemid ja/või regulatsioonid.

- Lisaks näitab meie analüüs, et konfliktid DSR-i jagamise üle teiste kasutajatega on suure tõenäosusega harvad. See annab omakorda võimaluse DSR-i ressursside tulemuslikuks jagamiseks DSO ja tarnijate või TSO vahel ning tuua kasu Eesti tarbijale. Samuti tekitab see vajaduse luua regulatiivne raamistik, mis aitaks kaasa DSR-i mõjusale kasutamisele süsteemi perspektiivist.

DSR-i väärtuse realiseerimiseks Eestis tuleb ellu viia mitmeid tegevusi seonduvalt regulatsiooni ja turudisainiga.

- Eesti peaks üle võtma peamised tootjate liitumise ja tarbimise juhtimisega seotud nõuded, mis tulenevad EL-i võrgueeskirjadest „Nõuded liituvatele tootmisüksustele" ja „Nõuded tarbijatele" ning samuti EL-i direktiividest (nt energiatõhususe direktiiv) ja poliitikadokumentidest (nt Energialiidu teatis), viies selleks sisse vajalikud muudatused elektrituruseadusesse ja võrgueeskirja.

- Eesti DSR-i ressursi olemusest tingituna (märkimisväärne väikesemastaabiline potentsiaal äri- ja kodumajapidamiste sektoris) võivad agregaatorid Eestis DSR-i arendamisel võtmerolli mängida. Seetõttu tuleb regulatsiooni selliselt kohandada, et agregaatorid saaksid kõigil olulistel turgudel osaleda.

- Suurem osa Eesti DSR-i potentsiaalist näib asuvat jaotusvõrgus. Seetõttu on TSO ja DSO vaheline liides väga oluline ning tuleb kaaluda omavahelise suhtluse korraldamise raamistiku loomist.

- Tänane regulatsioon võrgu arendamise motivatsiooniraamistiku osas tuleb seoses DSR-i kasutamisega ümber vaadata. Kui DSR-i rakendamisega välditakse võrgu tugevdustöid, peab motivatsioonisüsteem tagama DSO-le majanduslikult efektiivsete otsuste tasustamise. Üldjoontes tähendab see, et motivatsioon kasutada DSR-i ja seeläbi suurendada tegevuskulusid (tegevuskulusid nimetatakse praeguse regulatsiooni järgi mittekontrollitavateks kuludeks) peaks olema tasakaalus seetõttu vähenevate kapitalikuludega (nt trafodesse tehtavate investeeringute edasi lükkumine). Hoiatav on, et regulatsioon peaks arvatavasti sellest hoolimata toetama meetmeid varustuskindluse suurendamiseks (nt maa-aluste kaabelliinide paigaldamine), mis nõuavad kapitalikulusid. Üheks näiteks tegevuskulusid ja kapitalikulusid tasakaalustava motivatsiooniraamistiku kohta on praegune jaotusvõrkude regulatiivne raamistik Ühendkuningriigis (RIIO-ED1).

- Turuosaliste tegevus peab lähtuma äriloogikast, mis põhineb DSR-i väärtuse jagamisel; pakkujaid teavitatakse DSR-i tegelikust väärtusest ning pakkujad peavad olema teadlikud DSR-iga seonduvatest võimalustest ja omama nendele võimalustele juurdepääsu.

Võimalik tee edasi

DSR-i võiks kasutusele võtta enne alajaamade uuendamist selliselt, et see võimaldaks TSO-l samu ressursse hiljem süsteemiteenusteks kasutada.

DSR-i arendamine seisab Eestis silmitsi väljakutsetega. Pikas perspektiivis suurendab planeeritud desünkroniseerimine Baltikumis reservide vajadust, mis võiks olla peamine ajend DSR-i tekkeks. Ehkki see ei realiseeru enne 2025. aastat, tuleb DSR-i arendamisega valmisoleku tagamise ja testimise eesmärgil alustada juba varem – Balti riigid peavad enne võimalikku desünkroniseerimist tõendama võimekust töötada isoleeritud süsteemina. Oluline on disainida skeem, mis võimaldab üleminekut DSR-i ühelt kasutusviisilt teisele.

Lühemas perspektiivis näib DSR-iga kaasnev väärtus olevat tagasihoidlikum ning piirdub DSO-ga. Sellised skeemid võivad aidata kulusid oluliselt kokku hoida, kuid maht on tõenäoliselt väike (ligikaudu 10% alajaamade puhul on tuvastatud võimalus investeeringute edasilükkamiseks). Tarnijast lähtuv DSR on lühiajalises perspektiivis samuti tõenäoliselt piiratud. See olukord on sobilik väiksemale ja lihtsamale DSR-i skeemile, mida saaks kiiresti aktiveerida.

Et saavutada DSR-ist 2025. aastaks vajalik reservide tase, on enne selle potentsiaali realiseerimist tõenäoliselt vaja mitme aasta pikkust harjumise ja õppimise perioodi, kuna valmis skeem on tehniliselt keerukas (nt peab DSR vastama reservide pakkumise tehnilistele nõuetele, mis on rangemad kui nt hulgiturul osalemise reeglid) ja seab tõenäoliselt kõrgemaid nõudmisi DSR-i pakkujatele (DSR-il on palju erinevaid kasutusviise ning pakkujad peavad mõistma erinevate kasutusviiside väärtust, et DSR-i ressursse kõige kuluefektiivsemalt jaotada).

Eeldades et toetav regulatiivne ja tururaamistik on eeldustena paigas, tuleks DSR-i rakendamiseks Eestis teha järgnevad sammud:

- Lühiajalises perspektiivis võiks DSR-i rakendada (DSO eestvedamisel) enne alajaamade uuendamise vajadust. Tarnijatel võiks olla ligipääs DSR-ile hulgituru arbitraažiks ning selline ressursside jagamine võiks pakkuda lisatuge DSR-i teenuste edendamiseks. DSR-i rakendamise määr ja ulatus on tõenäoliselt tagasihoidlikud, kui võtta arvesse DSR-iga seonduvat väärtust nende eesmärkide täitmiseks, ning see piirdub kohalike võrkude vajadustega. Sellel perioodil on Eestil võimalus õppida teiste turgude DSR-i arengutest ja tehnoloogiast.

- Selline DSR-i rakendamine lühiajalises perspektiivis võiks hõlmata ka testperioodi, mis tõendaks kontseptsiooni toimivust juba võimaliku desünkroniseerimise eel (TSO toetusel). Võttes arvesse DSR-i tulevast kasutamist süsteemiteenusteks on soovitatav TSO-l DSR-i katsetada.

- DSR-i välja arendamine peaks toimuma selliselt, mis lubaks TSO-l samu ressursse kasutada tulevikus. Regulatsioonid peaksid tagama selle, et DSR-i saab jagada mitme osapoole vahel või et teistel osapooltel on lubatud kasutada DSR-i ressursse turul kauplemiseks või reservide pakkumiseks, kui neid parajasti ei ole vaja jaotusvõrgu toetamiseks.

- TSO poolt lõpuks vajatav DSR-i ulatus on palju suurem kui DSO poolt rahastatav, mistõttu TSO/tarnijad võiksid hiljem eest vedada vajalikke investeeringuid kogu riigis.

- DSR-i motivatsiooniskeemi väljatöötamisel tuleks arvesse võtta teiste turgude kogemusi.

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EXECUTIVE SUMMARY

Objectives of the project

Pöyry Management Consulting and PPA Energy[1] were commissioned to support Elering and other major stakeholders understand the role and value that demand-side response (DSR) could have in the Estonian system from now until 2030. There were five main areas of investigation:

- defining specific value drivers for DSR through discussion with Estonian market stakeholders;
- reviewing international DSR experience that is relevant to Estonia;
- identifying the best-fit options for DSR in Estonia based on the specific value drivers;
- quantitative analysis of the best-fit options for DSR in Estonia; and
- recommendations for the medium- and long-term development of DSR in Estonia.

This report summarises the outputs of the project.

Preferred DSR options for Estonia and their value

The value of DSR to the Estonian system rises over time. However, the value trajectory of DSR varies according to the uses by the stakeholders. The competing uses of DSR include wholesale trading in different markets to avoid price volatility, deferring investment in local networks and/or the provision of system services at a national level by 2025 when Estonia plans to desynchronise from the IPS/UPS electricity system. These services have different levels of value over time, and in different circumstances are either contradictory or complementary. The socio-economic value of DSR to the Estonian system can be categorised by national level benefits; i.e. savings from using DSR for wholesale market savings i.e. day-ahead, within day and balancing, system services and security of supply, and local level benefits; i.e. savings from using DSR to alleviate or eliminate local network issues.

National level benefits of DSR are modest in the short term but rapidly increase in the run-up to 2025 when desynchronisation takes place and Estonia must hold additional reserves

- While DSR can be used for the purposes of optimising day-ahead market costs in Estonia, the associated value of using demand-side response for this purpose is initially low. Our modelling shows that the wholesale market value of DSR increases over time, corresponding to annual benefits of around €0.5m/yr in 2020, €1.0m/yr in 2025 and €3.0m/yr in 2030. The low value is due to the relative size of the Estonian market to interconnection to the Nordic system with higher levels of flexibility.
- Uses of DSR for the within-day or balancing timeframe will increase due to increased wind penetration, but only to a limited extent, given the flexibility of the neighbouring Nordic system (based on the assumption that effective and more competitive ways are found of sharing flexibility across interconnectors in intraday and balancing timeframes). This means the overall market volume for Estonian domestic generators and DSR is expected to stay the same in the future (34 GWh up-regulation and 65 GWh down-regulation in 2014 and 111 GWh in the intraday market). If competitively priced (below incumbent price offers and neighbouring countries' offers) and enabled,

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[1] PPA Energy is a part of Ricardo AEA.

DSR could potentially access revenue from the balancing market; the balancing market size was €3.8m in 2014.

- When Estonia desynchronises the electricity system from IPS/UPS it will need to hold its own reserve. At that time, DSR could play a key role in the provision of holding reserve and deliver significant cost saving potential for the Estonian system. The value associated with the use of DSR for holding reserve is relatively high, especially compared to the (low) wholesale market use of DSR. When DSR can contribute to reserve provision, our modelling shows that the average price for holding up reserve is ~6,5 €/MW/hour and the annual market value of DSR for reserve provision is estimated at €14.4m (in 2030). The value of DSR lies in reducing the need for Estonian power plants to operate at part load, and/or reduce investment in plant to provide reserve. This also lowers Estonian CO_2 emissions[2]. If DSR were not able to provide reserve, our analysis indicates that additional generation capacity capable of reserve provision would be required. The exact dimensioning of the investment which would be displaced by DSR is rather uncertain: our modelling suggests that an additional unit of 125MW would be sufficient to meet the reserve requirements together with the rest of the generation park. The investment displaced could be approximated to half the cost of building the Kiisa 2x125MW units, i.e. ~€68m[3]. Importantly, this finding rests on the assumption that Estonia must provide all its reserve from internal sources. If reserve could be procured from neighbouring markets, this could reduce the overall value associated with reserve provision in Estonia and this should be investigated further.
- DSR could make a meaningful contribution to Estonian security of supply by compensating for decreasing firm capacity and increasing demand on the Estonian system. DSR would be especially valuable in this respect around 2025 when the local margin in Estonia turns negative by 200MW. There is a trend, driven by the European Commission, to move towards a regional approach to security of supply. For example, the Communication on the Energy Union Package (COM/2015/0080) calls for a more regional approach to security of supply in electricity and gas markets. In light of this, twelve European countries recently signed a declaration for regional cooperation on security of supply within the European energy market[4]. Adopting a regional perspective to the security of supply analysis shows that Estonian DSR does not make a meaningful impact to the capacity margin (see Figure 37). Elering's Security of Supply report reveals that under N-1-1 conditions there could be a lack of capacity, meaning additional DSR or generation capacity may be needed in 10-15 years to cope with unplanned outages.

In conclusion, the main driver of value at a national level is the requirement for TSO reserve services which will accompany the planned programme of desynchronisation from the IPS/UPS system. This is planned for 2025, although for testing purposes the reserve readiness must be in place a few years earlier.

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[2] Compared to a baseline where DSR is not available.

[3] The total cost of the project was around 135 million euros. Source: http://elering.ee/emergency-reserve-power-plants-2/

[4] http://europa.eu/rapid/press-release_IP-15-5142_en.htm

Local level benefits to the DSO could be accessible in the near term (depending on the DSO schedule to reinforce substations and DSR availability), but are relatively modest in terms of helping to defer investment

DSR can provide value to the Estonian distribution system through relieving network congestion and allowing network investments to be deferred. However, the value is relatively low compared to the value associated with national level benefits from DSR.

- If DSR is readily available, and can be secured cheaply and reliably by a DSO, then there is potential for DSR use to facilitate a lower capacity, cheaper distribution network. Savings for the DSO using DSR (to avoid investments in network reinforcement) are estimated to be around €0.5-0.7m/yr.
- DSR utilisation rates by the DSO are low, particularly for two-transformer arrangements, and concentrated in peak winter days, which means that there is the potential for DSR to simultaneously offer services to the DSO and at national level.
- There is a limited number of substations (<10% of the total number) where DSR may be relevant in the next decade. The data made available to us has not enabled us to take a position on how much of this is front-loaded or back-loaded; but the use of DSR (if available) can be considered immediately where there are substations being reinforced or replaced. Some of these sites could be potential trials for DSR.
- There may be some sites where it is economically beneficial for the DSO to procure DSR solely for network use.

DSR has the potential to provide benefits to multiple Estonian stakeholders for potentially competing uses. As the benefits are not distributed evenly, there is a case to design a framework to enable costs of DSR to be shared efficiently between the different stakeholders. There is also an issue about competing uses, and the need to use DSR where it is most valuable

- Most benefits of DSR appear to be at the national level and associated with reserve provision. There appear to be limited benefits for the DSO. It is also the case that, according to the findings from previous studies, significant (>60%) DSR potential (volume) is located on the distribution network (residential, offices).
- Based on our calculations, most DSO schemes will require sharing of DSR use (for the wholesale market or reserve) to achieve a significant economic benefit. If this occurs, there is scope for significant savings in DSO network investment. Appropriate sharing schemes and/or regulations need to be in place to help this process happen.
- Moreover, our analysis indicates that conflicts in use of DSR with other users are likely to be rare. This further raises the possibility to allow effective sharing of DSR sources between a DSO and suppliers or the TSO and benefit the Estonian consumer. It also raises the need to consider a regulatory framework that facilitates the efficient use of DSR from a system perspective.

To realise the value of DSR in Estonia, a number of steps need to be taken related to the regulatory and market structure around DSR

- Estonia should incorporate core requirements of the *Requirements for Generators* and the *Demand Connection* EU Network Codes as well as of the EU directives (e.g. energy efficiency directive) and policy documents (e.g. communication on Energy Union) in respect of the connection of generation and the use of demand-side response by making appropriate modifications to the Electricity Market Act and the Grid Code.

- The nature of the Estonian DSR resource, with significant small-scale commercial and household potential, means that aggregators could play a key role in developing DSR in Estonia. Therefore regulation should be modified to enable aggregators to participate across all relevant markets.
- Much of the DSR potential in Estonia appears to be located on the distribution network. Therefore, the interface between the TSO and DSO will be important and a framework for managing this interaction must be considered.
- The existing regulatory network incentive framework needs to be reconsidered for DSR use. To the extent that DSR avoids the need for network reinforcement, the incentive arrangements for the DSO must ensure that economically efficient decisions are rewarded. At a high level, this means that the incentives to call DSR and thereby increase operating expenditure (OPEX is currently a pass through item[5]) in order to reduce CAPEX (e.g. deferring investments in transformers) should be aligned. The caveat is that regulation should probably still promote measures to increase security of supply (such as undergrounding) which require CAPEX spend. One example incentive framework which balances OPEX and CAPEX is the current regulatory frameworks for distribution networks in the UK (RIIO-ED1[6]).
- The actions of the stakeholders will need to be driven by a commercial framework in which it is important that the industry shares the value from DSR; the value of DSR services is effectively signalled to providers and providers need to be aware of and able to access the opportunities associated with DSR.

Potential way forward

DSR could be rolled out in advance of replacement of substations in a way that permits the use of resources by the TSO later for system services

DSR in Estonia faces a development challenge. In the long term, desynchronisation will increase reserve requirements in the Baltics and this could be the key value driver for DSR. Although this will not become a reality until 2025, development for preparedness and testing purposes will need to start even sooner – the Baltics will need to demonstrate the ability to operate as an isolated system before desynchronisation. The important issue is to design a scheme that allows a transition between the different uses of DSR. The concept is illustrated in Figure 1.

In the shorter term, the value associated with DSR appears modest and localised to the DSO. Such schemes can achieve large cost savings but the volume is likely to be low (some 10% of substations have been identified as suitable for investment deferral). Supplier driven DSR is also likely to be limited in the short term. This situation lends itself to a smaller and simpler DSR scheme that could be activated quickly.

To achieve the necessary level of reserve provision from DSR by 2025, it is likely that a period of familiarisation and learning of several years is required before the potential can be realised as the mature scheme will be technically challenging (e.g. DSR must meet technical requirements for reserve provision which are more challenging than requirements for e.g. wholesale market use) and potentially more demanding for DSR providers (there will be a spectrum of DSR uses and providers will need to understand the value of the different DSR uses to allocate DSR resource most cost effectively).

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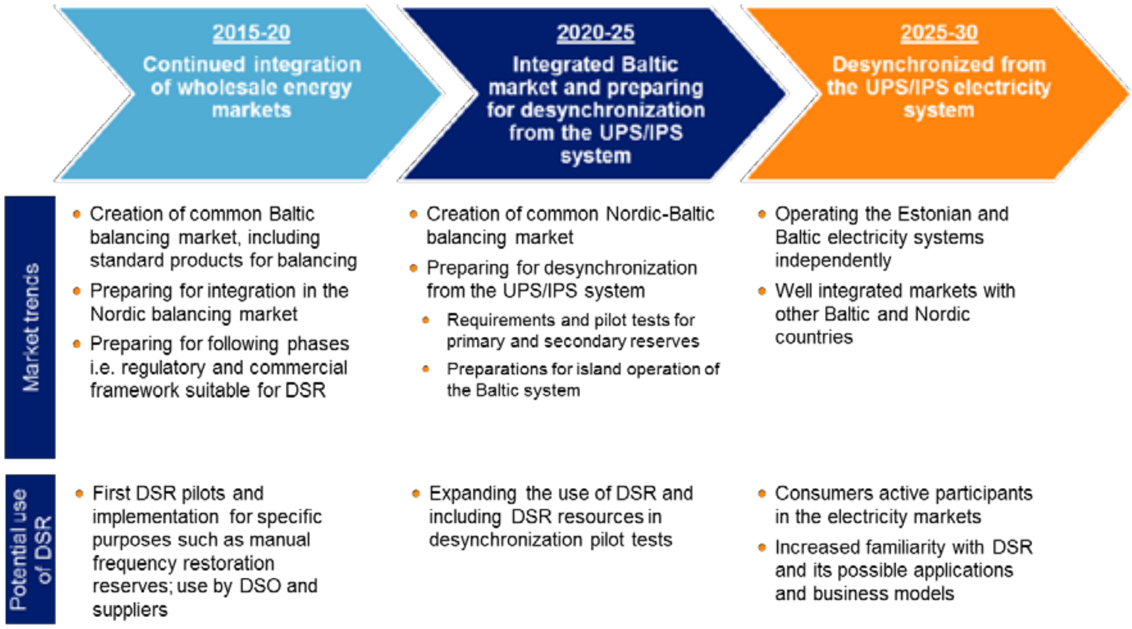
5 Uniform Methods for Calculating Electricity Network Charges, Estonian Competition Authority, 2014

6 https://www.ofgem.gov.uk/network-regulation-riio-model/riio-ed1-price-control

Assuming the supporting regulatory and market framework is in place as a pre-requisite, the following could be a development path for DSR in Estonia:

- In the short term, DSR could be rolled out (led by the DSO) in advance of replacement of substations. Suppliers could access DSR for wholesale market arbitrage and this sharing of resource could provide some additional support to bring forward the DSR services. The rate, scale and level of deployment of DSR is likely to be modest given the value associated with DSR for these purposes, and it will be localised based on needs of the local networks. During this period, Estonia can learn from the development of DSR and technology in other markets.
- Such a roll out could include a trial period as a proof of concept in advance of the desynchronisation (and potentially support from the TSO). Given the future use of DSR for system services, it is recommended that TSO trials of DSR take place.
- The roll out should be done in a way which permits use of the same resources by the TSO at a later point. Regulation should ensure that DSR may either be shared by multiple parties, or that other parties are allowed to use DSR resources for market trading or reserve when they are not needed for supporting the distribution network.
- The scale of DSR eventually needed by the TSO is much bigger than a DSO is likely to fund, and the TSO/suppliers could later drive investment across the country.
- The experience from other markets (as highlighted in chapter 2) should be taken into account when designing the DSR incentive scheme.

Figure 1 – High level roadmap for the development of DSR in Estonia



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1. INTRODUCTION

The Estonian electricity market, alongside the other Baltic electricity markets, Latvia and Lithuania (Figure 2) are bordered by the Nordic electricity markets in the North-West and the Russian and Belarusian electricity systems to the East. There is a land border between Lithuania the most Southern Baltic market and Poland (though as of yet there is no interconnector capacity between the two countries, with commissioning of the LitPol interconnector scheduled for late 2015).

Figure 2 – The Nordic and Baltic power markets

Numbers in the figure are daily capacities (MWh) of interconnection on the day-ahead market on June 22nd 2015.

Source: Nord Pool Spot AS

Until 1991, the Baltic countries were integrated with the Soviet Union. As a result, the Baltic power system is highly integrated with the UES power system (Unified Energy System) in terms of physical connections and system stability (i.e. the Baltic markets are synchronous with the UES market). On 1 May 2004, the Baltic countries acquired full European Union (EU) membership status, and began the process of acceding to the EU energy markets.

Broadly speaking, the Baltic electricity markets are currently defined by the following characteristics:

- Members of the integrated Nord Pool market (along with Denmark, Sweden, Norway and Finland).
- Highly integrated with one another.
- Part of the UES Russian network i.e. 'synchronous'.
- Markets are relatively small (in terms of demand).
- Markets have historically been dependent on one power source in each market (oil shale in Estonia, hydro in Latvia and nuclear power in Lithuania) and one vertically integrated national utility.

The current fundamental characteristics of the Baltic power markets are important determinants of three elements:

- The design of energy policies, in terms of what changes to market fundamentals and market design are required, and how policies will facilitate these changes.
- How will the Baltic markets comply with EU market coupling policies, and what are national policies for connection to other countries?
- How the commercial parties will respond to policies?

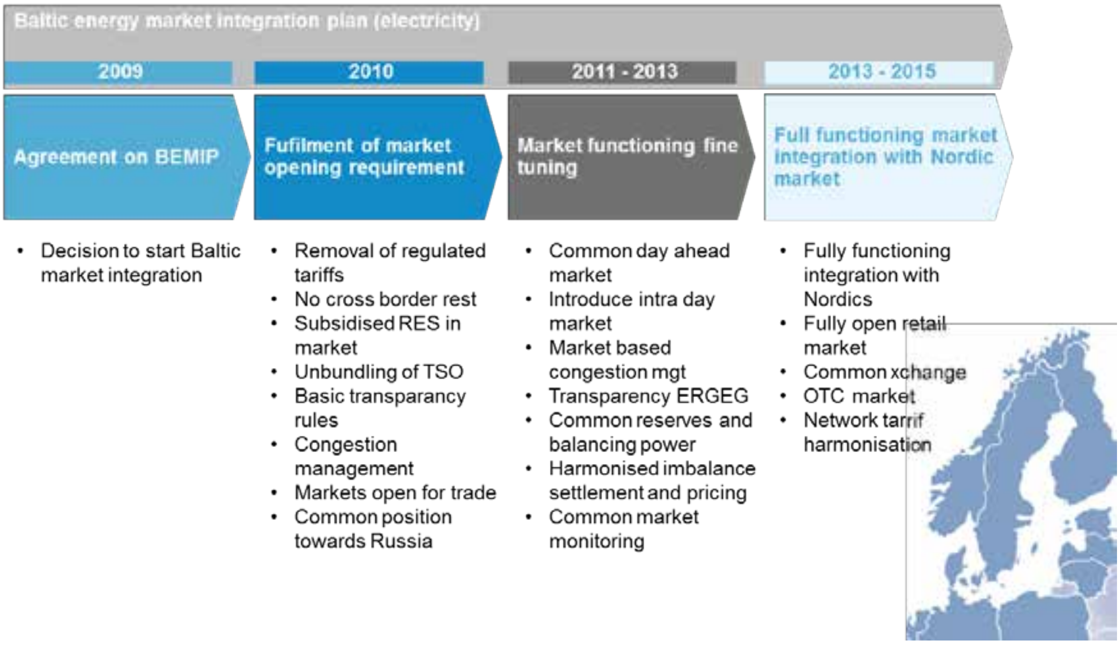
1.1 Closer connections with Nordic and European market

The Baltic Energy Market Interconnection Plan (BEMIP) has two main objectives relating to electricity markets: (1) full integration of the Baltic electricity market into the European electricity markets and (2) strengthening of the interconnection capacity to the EU neighbouring countries. These objectives serve in pursuing of one of the three EU energy policy goals, namely security of supply.

As a main objective of the creation of a fully functioning and integrated energy market supported by the necessary infrastructures in order to strengthen energy security in the Baltic Sea Region. According to the BEMIP, the interconnection capacity between electricity systems in the Nordic and the Baltic countries will be strengthened with new cables to Finland (Estlink II; entered in operation in 2014) and Sweden (NordBalt in 2015).

The interconnection between Lithuanian and Polish transmission grids will be followed by building a new back-to-back converter station and strengthening internal high voltage transmission grids in Poland and Lithuania. The commissioning of 500 MW interconnection is planned in 2015, and another 500 MW in 2020.

Figure 3 – Overview of BEMIP plan (for electricity)



In the BEMIP the electricity market design has been agreed to be implemented based on the Nordic electricity market model. A specific "Roadmap" that describes practical steps on how to reach the new market model and aims at removing the barriers for a regional electricity market in the Baltic States in conformity with the EU internal electricity market rules has been proposed. The Roadmap consists of four steps and it is planned to be implemented by end of 2015[7] (see Figure 3). Each step contains concrete actions to be executed, covering for example, removal of regulated tariffs, separation of TSO activities and roles, removal of cross-border restrictions, establishment of market based constraint management as well as common reserves and balancing power market, full opening of the retail market and establishment of common power exchange for physical trade in Nordic and Baltic area. Progressing on these market design aspects represents a crucial element for the integration of the electricity systems of the three Baltic States into the Nordic electricity market system.

The fact that the Baltic countries are physically integrated to the Russian and Belarus synchronous electricity systems is a characteristic that entails special challenges; particularly when considering the difference in scale between the Russian and the Baltic electricity systems. In December 2014, the Baltic TSOs announced that they had agreed on a roadmap with a target of desynchronising Baltic networks by 2025.

Closer integration with European markets also means that the Baltic states have adopted EU market rules and policy objectives including 2020 targets. In the future, the Baltic markets will also need to implement measures to comply with the EU network codes.

[7] A Memorandum of Understanding on a refined BEMIP extension plan was signed in June 2015, available at: https://ec.europa.eu/energy/sites/ener/files/documents/MoU_Final_to%20be%20signed%20on%208%20June_v2.pdf

In general all Baltic countries are in favour of BEMIP and the governments have set their action plans to achieve the goal according to the schedule set by EU. Estonia is broadly on schedule with its BEMIP process plan while Lithuania and Latvia have been trying to catch-up with their plans.

Key outstanding issues in BEMIP can be summarised as:

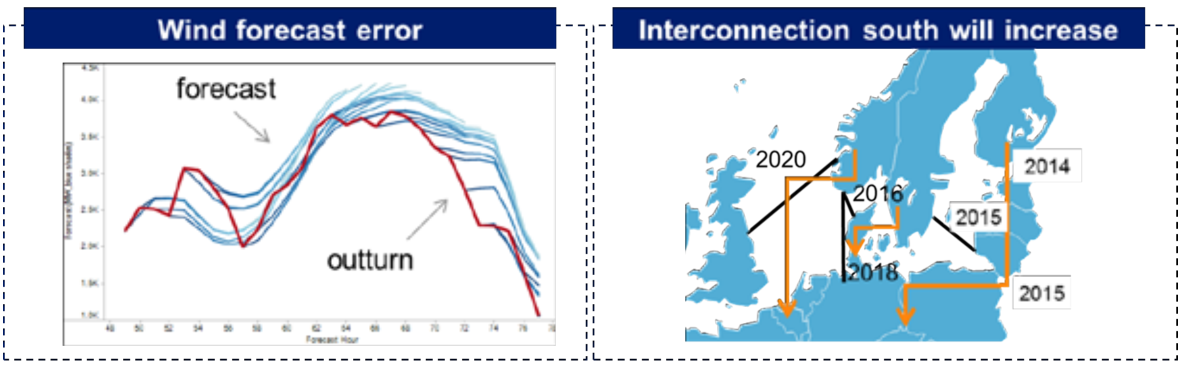
- Ensure security of supply in the Baltic countries means securing peak-load and reserve capacity supply adequacy and, if necessary, demand-side response in disturbance situations and competitiveness of Baltic producers in integrated power markets.
- Finalise agreements on common principles for trading and interconnection capacity allocation towards third countries.
- Create preconditions for establishment of financial market: first OTC trading/brokers, then financial market place.

1.2 Future outlook

Overall, it is expected that more flexibility will be needed to balance the Estonian system in the future. This is because (see Figure 4):

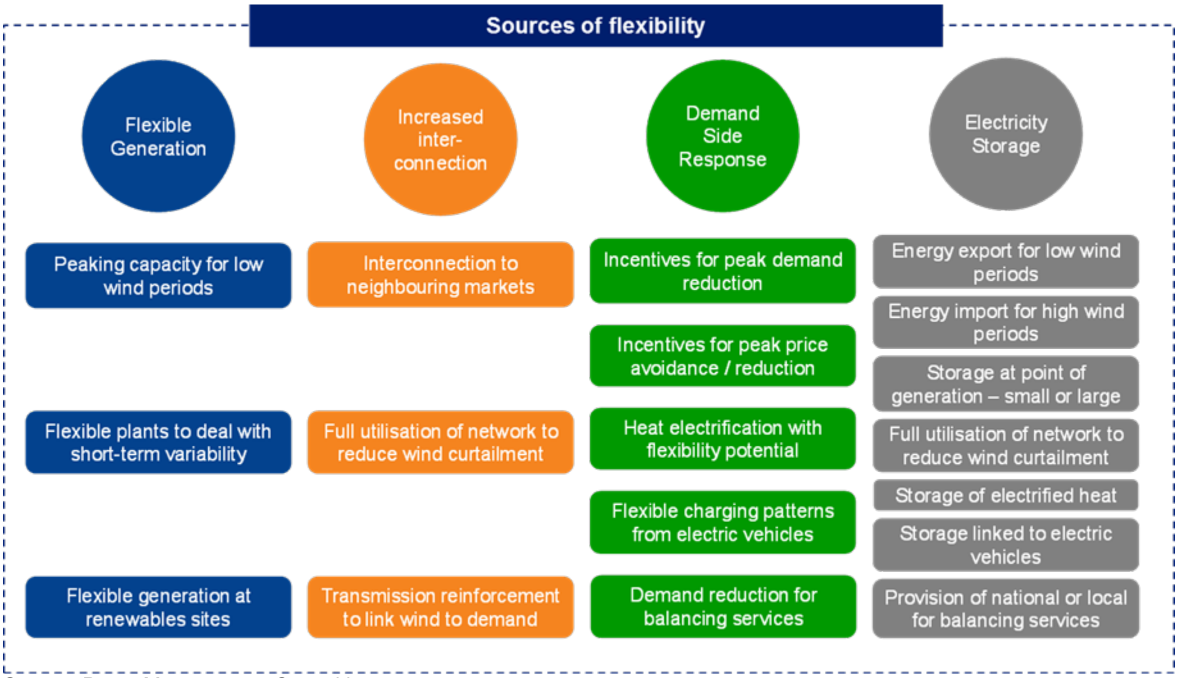
- Over the next decade, the Estonian market will face an expansion of intermittent renewable energy supply as the country seeks to meet its EU renewables and carbon emissions targets.
- Ensuring security of supply in the Baltic markets means securing peak load reserve supply adequacy (possibly through demand-side response).
- Increasing integration of the Baltic markets with Continental European markets will expose the (comparatively small) Baltic markets to the influence of intermittent generation in neighbouring markets.

Figure 4 – Drivers of the increasing need for flexibility in Estonia



This flexibility could be provided through four possible sources: flexible generation, interconnection, Demand-side Response and electricity storage. These options and their flexibility potential from an energy balancing perspective are illustrated in Figure 5. Of these options, this study focuses on Demand-side Response.

Figure 5 – Four potential sources of flexibility



Source: Pöyry Management Consulting

1.3 Roles, responsibilities and uses of demand-side response

Incorporating large volumes of variable generation on the system is seen as a major challenge for future system operation. Demand-side response (DSR) is one of the measures that could play a significant role in incorporating large volumes of renewable generation[8].

The role of DSR is complex as it can be used for different purposes by different stakeholders. Pöyry investigated this topic for the UK government[9], assessing the difference between the use of DSR for supply driven optimisation as opposed to network driven optimisation. A summary is supplied below and Table 1 gives an overview of the applications of DSR and the value of DSR to different parties.

Suppliers may wish to use DSR to manage their wholesale costs and portfolio management. The value of this service is expected to increase as the amount of flexible generation on the system decreases and inflexible generation increases; DSR can be used to manage price volatility and price spikes and hence costs.

These issues are intrinsically related to the management of intermittent generation. Suppliers (vertically integrated entities), the transmission system operator (TSO) or even portfolio players may wish to increase demand to avoid intermittent curtailment or reduce

[8] Pöyry, 2010. Options for low carbon power sector flexibility to 2050. http://www.poyry.co.uk/sites/www.poyry.uk/files/fourthbudget_supportingresearch__Poyry_powersectorflexibilityto2050.pdf

[9] Pöyry, 2010. Demand-side response: conflict between supply and network driven optimisation. http://www.poyry.com/sites/default/files/151_optimal_demand_side_response_v3_0_decc.pdf

demand to mitigate the effects of low wind periods (low wind periods typically coincide with peak price periods especially in the winter).

More generally, the TSO may wish to use DSR to optimise network investment; for energy balancing purposes (within the balancing mechanism); for system balancing (typically within half hour to real time) and for managing network fault situations (either pre or post fault). Short Term Operating Reserve (STOR) in the Great Britain (GB) market is an example of system services used by the TSO and which includes DSR units.

The distribution system operator (DSO) may wish to use DSR to avoid or defer network investment (and provide additional investment redundancy); manage customer outages and use DSR to optimise operational and capital costs; integrate distributed generation; and manage network constraints within operational timescales.

A supplier will use DSR to manage its position, this includes:

- Energy balancing (MWh/settlement period), either on a portfolio basis or an individual basis.
- Avoiding costs incurred related to running or building new generation capacity.
- Managing CO_2 emissions.
- Provision of DSR services to DSOs and TSOs.

All of these uses of DSR can lead to issues of conflict when different parties want to use the same DSR at the same time or when the use of DSR by one party has a negative impact on another party. One example here would be when the TSO may want to use DSR to reduce peak demand and this introduces a problem at the local network (DSO level) – see section 4.2.3. These potential conflicts and the relative price signals that different parties could send have been investigated in the GB market for National Grid and Electricity North West[10].

All of this potential conflict implies that to minimise conflict and inefficiencies in the system, a common regulatory framework governing the use of DSR may be beneficial. With a suitable market structure DSR can serve multiple purposes and parties in an efficient manner.

[10] Pöyry 2011. Assessment of DSR price signals. http://www.poyry.com/sites/default/files/assessment_of_dsr_price_signals.pdf

Table 1 – General applications of demand-side response

Application	Value of DSR	Entity that will use DSR
Energy price arbitrage	Peak – off peak spread, incorporate renewable generation more cost effectively (e.g. avoid curtailment)	Supplier, vertically integrated utility, balance responsible party, aggregator
Portfolio shifting & optimisation	Avoided cost of procuring balancing & cost of incurring imbalance costs	
Generation capacity adequacy	Avoid investment in generation	
Frequency control* (FCR, FRR, RR)	Cost effective reserve procurement and requirement for reserve	TSO
Energy balancing	Cost effective procurement of reserve capacity for balancing markets	
Managing network constraints	Avoid re-dispatch costs, optimise network investments and delay investments	
Constraint management	Reduce or defer investment	DSO
Manage customer outages	Avoid outage penalties	
Reactive power / voltage control	Enable connection of more distributed generation[11]	

*FCR = Frequency Containment Reserve, FRR = Frequency Restoration Reserve, RR = Restoration Reserve

Source: Pöyry Management Consulting

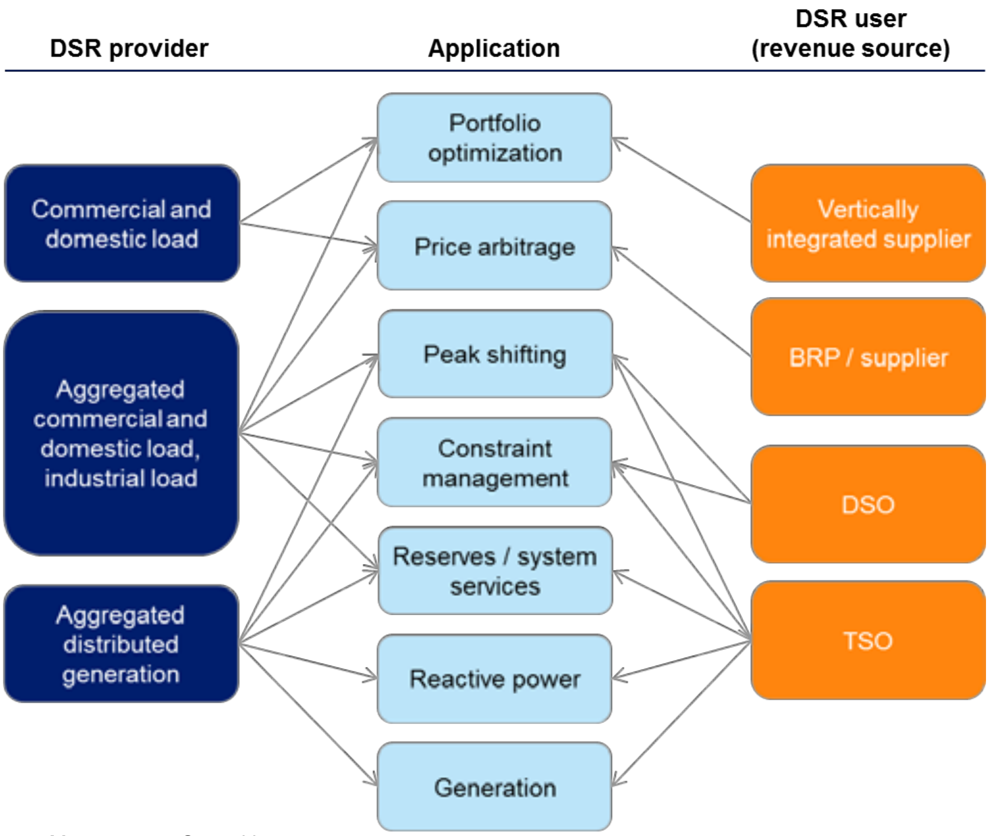
Providers of demand-side response are important to consider. Providers of DSR interact with users of DSR through the applications they offer.

Figure 6 gives an overview of the providers of demand-side response, the applications that they offer and the DSR users (the party that is paying for a service provided by DSR). It clearly shows that DSR providers can offer their DSR for multiple applications. Likewise, the applications have multiple users (or revenue sources). Moreover, the different users may want to use DSR for the same application. This implies there could be a natural market and hence competition for DSR providers to contract certain DSR applications for specific purposes. As competition for the DSR resource is likely, the question of resource allocation arises and with it the strength of price signal that can be

[11] The use of DSR for this purpose may benefit the generator instead of the DSO if they are responsible for possible reinforcements to enable connection of generation in the network

sent by the different revenue sources to ensure that the application is available to them. DSR providers will need to understand which applications are the most profitable. Previous studies have shown that relying on price signals can create inefficient market outcomes and therefore imply that a regulatory framework may be required to ensure that the different users of DSR can access the resource and minimise system costs[12].

Figure 6 – Providers, applications and users of demand-side response



Source: Pöyry Management Consulting

[12] Pöyry 2011, Assessment of DSR Price Signals

1.4 Structure of this report

- Chapter 2 presents the summary of findings from the international case review.
- Chapter 3 presents the results of the stakeholder interviews and research that was used to identify the best fit options for DSR in Estonia.
- Chapter 4 presents the results of the quantitative analysis.
- Chapter 5 presents conclusions and recommendations.

1.5 Conventions

- All monetary values quoted in this report are in Euros in real 2013 prices, unless otherwise stated.
- Annual data relates to calendar years running from 1 January to 31 December, unless otherwise identified

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2. EXPERIENCES FROM INTERNATIONAL DSR CASE EXAMPLES

In this chapter, we present key insights from a review of international examples of DSR measures and mechanisms which are being implemented, trialled or thought of elsewhere. Reviewed examples are presented in Table 2.

Table 2 – Selected international case examples

Owner	Initiating parties	Country	Description
Statnett	TSO	Norway	The TSO is using DSR to manage and balance the system
Fingrid	TSO	Finland	The TSO is using DSR to manage and balance the system
DONG Energy	Supplier, generator	Denmark	Provides an example of intelligent energy management of different types of generation or demand and how a VPP model may work
National Grid	TSO and in some cases end users or third parties (aggregators)	Great Britain	The role which DSR plays in the various National Grid products such as Short Term Operating Reserve market, the TRIAD management and the Demand-Side Balancing Services requirements
UK Power Networks	DSO, third parties and suppliers	Great Britain	A large scale smart energy project testing a number of issues from the introduction of innovative contractual arrangements between customers and DSO and the use of tariffs to change behaviour and patterns of consumption
ESB and EirGrid	Supplier, generator, TSO	Ireland	Time of use tariffs in Ireland being mandated as part of the smart metering roll out
EirGrid	TSO	Ireland	The Winter Peak Demand Reduction Scheme (WPDRS) was introduced as an incentive to business customers to reduce electricity consumption during the power system's peak hours in winter months.
Elektro Ljubljana	Aggregator	Slovenia	Participation of VPPs in the provision of tertiary reserve services to the TSO
RTE	Supplier, TSO	France	An overview of how DSM is integrated within the French market design. DSR is used in the balancing mechanism, as part of the market and for portfolio optimisation
German TSOs	TSO	Germany	Use of large consumption units connected to high-voltage networks to maintain grid and system security

The geographical focus of our analysis is the EU with special focus on the GB, Ireland, France, Germany and the Nordic countries. Examples for analysis have been chosen so that the TSO is the initiating party in most cases. It should be mentioned that for DSR use in general, not only in the examples included in Table 2, the TSO is at least the facilitating party and more often the primary customer for DSR services.

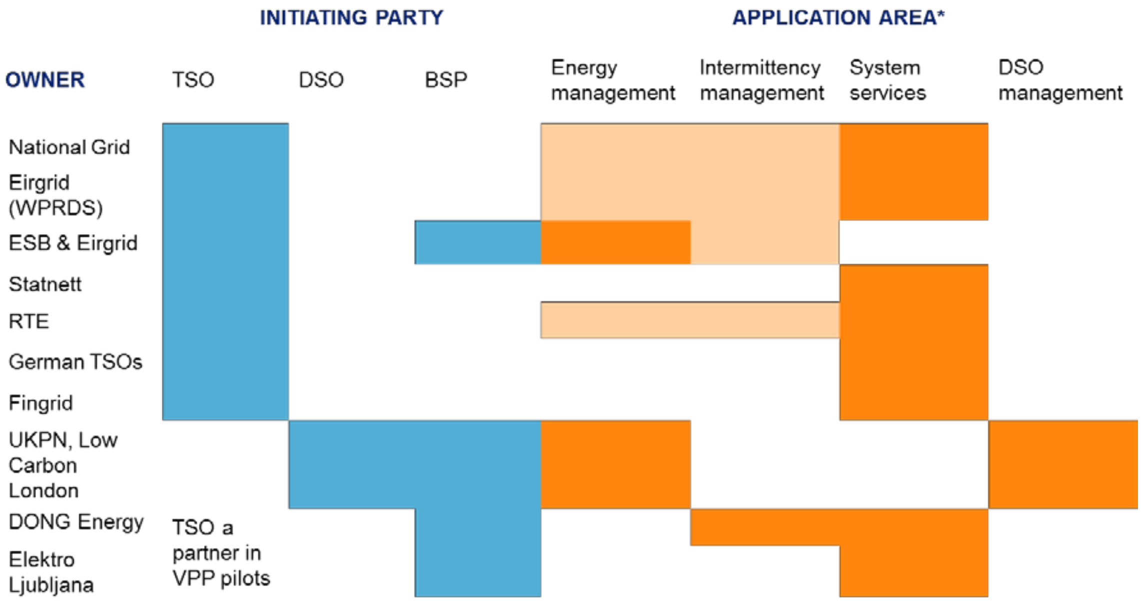
The international cases have been categorised based on application areas. Different market stakeholders can use DSR in four application areas:

- **Energy management:** Suppliers may wish to use DSR to manage their wholesale costs. In the future, we anticipate greater price volatility in the system due to the unpredictability of intermittent generators. Suppliers may therefore wish to manage their wholesale costs by using DSR, especially at times when wholesale prices will be high. In addition, end customers may wish to reduce their own wholesale costs to increase their competitiveness.
- **Intermittency management:** Suppliers, the TSO or even portfolio players may wish to increase demand to avoid intermittent curtailment or reduce demand to mitigate the effects of low wind periods (low wind periods typically coincide with peak price periods especially in the winter). In addition, the TSO may wish to use DSR to reduce the level of peak generation capacity needed on the system.
- **System services:** DSR can also be used for system services purposes. The TSO may also wish to use DSR to manage unplanned generation outages or to manage some transmission network constraints.
- **DSO management:** Finally, the DSO may wish to use DSR to manage distribution network constraints and to therefore defer or avoid network reinforcements.

Strictly speaking, intermittency management is not separate from the other application areas, but is more a scale issue for the other areas. It is however listed here separately because it is a major driver for increasing need for flexibility in various electricity systems in the EU.

DSR use has been mostly initiated by TSOs for system services and energy management in response to an urgent need. Mapping of the international cases according to their primary and secondary application areas and initiating parties is illustrated in Figure 7. More recently, there has been interest to understand the role of DSR in the future system.

Figure 7 – Application areas in international cases



*Darker shade refers to primary application, i.e. what is the main reason for DSR use, and lighter shade refers to secondary application area

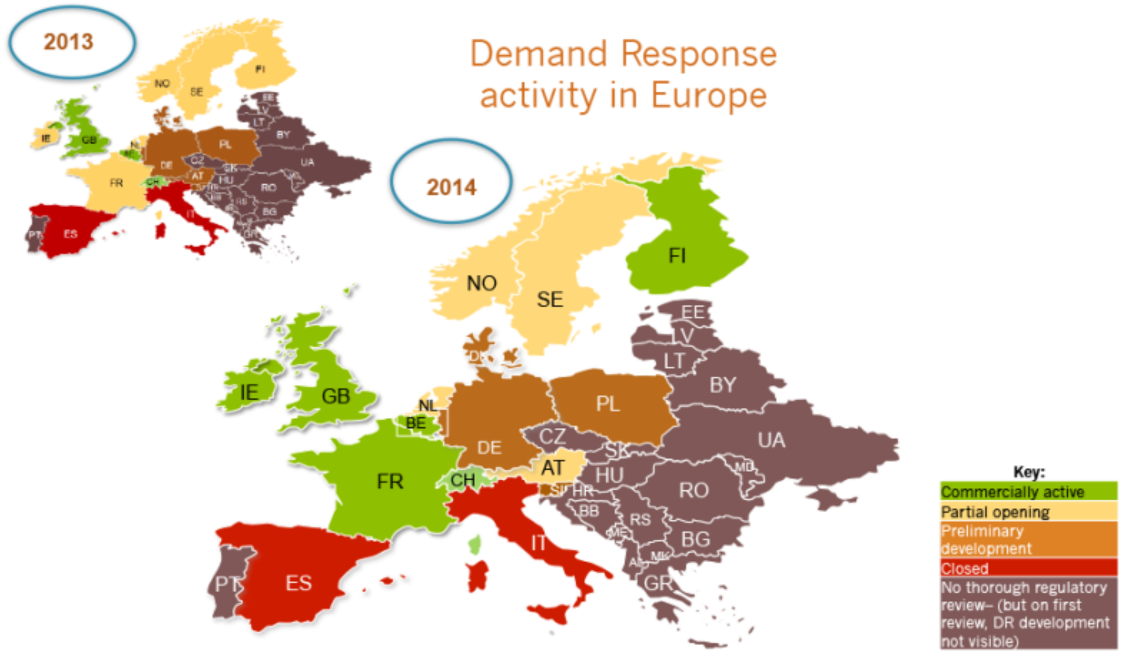
In addition to main drivers and triggers for the use of DSR, other key insights and recurring topics across different projects and schemes are presented below.

2.1 Current state of DSR

The DSR market is reasonably advanced across the EU but progress varies significantly across member states. A number of projects and schemes have been successfully implemented in various countries and these projects cover the full spectrum of DSR applications and business models.

The Smart Energy Demand Coalition (SEDC), an industry group promoting the requirements of demand-side programs in European electricity markets, publishes an annual study to investigate the market opening status for DSR across selected European markets. Figure 8 provides a snapshot of the status in 2014 and highlights progress from 2013.

Figure 8 – Summary of current status of DSR in Europe.



Demand Response Map of Europe 2013-2014

Source: SEDC, "Mapping demand response in Europe today"

Based on feedback from the organisations contacted during the literature review, in the short term, DSR is being developed in systems where local conditions suggest flexibility will become scarce in the future (due to e.g. thermal plant retirement in Finland). The requirements for flexible capacity in such countries as GB and Ireland have been more substantial compared to the Central European or Nordic countries where significant interconnection (and flexibility from hydropower generation) is present and as a consequence, GB has one of the largest number of DSR schemes overall (STOR, TRIAD, DSBR, Capacity mechanism).

In the longer term, it is widely expected that more flexibility will be needed to manage the system on an intra-day basis with higher levels of renewable generation on the system – DSR can contribute to future flexibility requirements, hence more DSR schemes are being investigated and implemented across EU.

2.2 How will the various schemes work together?

While individual projects and stand-alone schemes work well to verify certain applications or technologies, there is a need for a holistic framework to unlock the full potential of DSR participation and enable DSR to develop and innovation to occur. As was mentioned above, the GB market is one of the most advanced in terms of DSR schemes but there is uncertainty in relation to how these schemes effectively complement each other and the added value which each scheme brings to the system. This is partly because the system has been developed in a piecemeal fashion in response to the demand of participants.

Intuitively, a holistic approach could be beneficial when implementing DSR in a particular country. Such an approach would take into account current and future DSR use and assess how the schemes that are implemented may interact.

2.3 Contractual arrangements

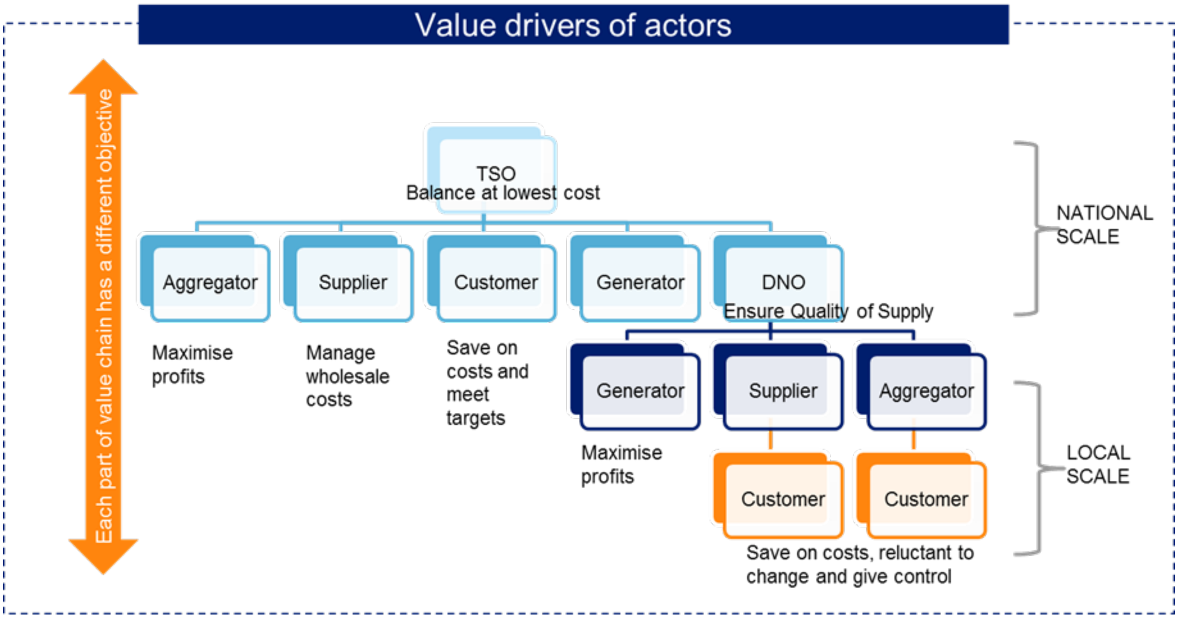
Contractual arrangements are an important component of DSR implementation. Customers can be discouraged by complicated contracts. Innovation in the management of electricity networks, through increased DSR, will inevitably lead to changes in relationships between participants. As an example, ancillary services were not always familiar topics for potential DSR providers in the international cases. Consequently, technical requirements of ancillary services can be hard to understand for aggregators and consumers so simplicity in contracts related to, for example, transparency around compensations and penalties is crucial.

Historically, the relationships between 'customers and the supplier' and 'customers and the DSO' have been relatively straightforward, rarely involving anything beyond supply restoration and new connections. In the Low Carbon Network Fund pilots in GB, an increase in the direct interactions between the DSO and the customer has been evident. The importance of understanding customer behaviour and the customer role within the smart energy system cannot be underestimated in understanding the new relationships with customers. Lack of customer understanding can lead to difficulties in engaging customers in new pilots and mechanisms.

2.4 Interactions between market stakeholders

The future interactions between the various parts of the value chain are not always well understood when DSR schemes are implemented. When DSR participation is widened to include different stakeholders in addition to specific projects or schemes, cross-stakeholder coordination is necessary to avoid conflicts and ensure cost effectiveness. In other words, it should be ensured that there are no duplicate or contradicting DSR actions from different parties. Figure 9 illustrates the value drivers of different market participants, which can lead to potentially conflicting behaviour.

Figure 9 – Value drivers of actors



Source: Pöyry Management Consulting

In many European Member States, it is arguable whether the current market model allows aggregators to compete effectively, as bilateral agreements between them and balance responsible parties[13] (BRP) or suppliers are required, effectively allowing BRP/suppliers to block market entry for aggregators (e.g. in Norway and Germany) because aggregators cause BRP/suppliers to be out of balance.

Another key issue to maximize the use of DSR is to understand how the needs of the TSO and DSO overlap and therefore provide clarity on the type of commercial arrangements and regulatory framework required in the future. In addition, DSR can devalue generation – in the short term at least - so vertically integrated energy companies might not be interested in contracting DSR.

2.5 Data reliability

Overall confidence in data is vital if majority of distributed sources are to be enrolled and monitored as part of a DSR scheme. Utilities are now seeking to become more proactive in decision making and framing their strategies on ‘analytics’ which are based on data collected in the network. As utilities move from historical analytics to near real-time predictive analysis, it is very important that all stakeholders know that information provided to them is accurate. All this applies also to DSR as the accuracy of data will be crucial for automating response in different DSR schemes.

As the number of data-collecting devices increases, data volumes could become challenging. In particular, dealing with non-standard data produced by devices procured from different manufacturers could be a challenge. Combining the use of central and

[13] The balance responsible party (BRP) is responsible for the balance of the market participants in its balance area. In other words, it is the BRP’s responsibility to ensure that the amounts of electricity bought from or put into the grid by market participants in its balance area and the amount of electricity sold or taken out of the grid in the same trading period are in balance.

decentralized analytical tools, in addition to the efficient sharing of a selected minimum set of data between locations, is crucial.

2.6 System reliability

Safeguarding against ICT failures is important if DSR is to be successfully implemented. There is a significant increase in ICT failure risk in a future where the DSO and TSO are interacting with a much broader group of stakeholders. It is important to give access to devices and data to the relevant stakeholders. However, this has to address any privacy and security concerns (cyber-attacks) that may be associated with them.

The loss of ICT services in the major control centres could make it challenging for system operators to request reserves in event of faults, and during system constraints. Adequate risk reducing measures are required to ensure that ICT redundancy is adequate and as a final back stop manual system operation is possible. Robust ICT solutions have to take into account the effect of their failure on other mechanisms that they interact with. This includes network capacity allocation software and DSR bidding and scheduling decision software.

3. DSR OPTIONS FOR ESTONIA

In this chapter the favourable DSR options for Estonia are derived. The process for derivation of the best fit DSR options for Estonia has consisted of desktop research, a number of interviews with the major stakeholders and a workshop with all stakeholders in Tallinn.

The chapter is structured as follows:

- Drivers for demand-side response in Estonia.
- Key Stakeholder perspectives on DSR in Estonia.
- Review of the different DSR applications and relevance to Estonia.
- EU regulation and network codes relevant to DSR use and applicable in Estonia.
- Key regulatory issues to the implementation of DSR.
- Business models and contracts for DSR.
- Technical considerations for reserve provision from DSR.

3.1 Drivers for demand-side response in Estonia

This section presents a review of the main drivers that were identified for DSR development in Estonia.

3.1.1 Desynchronisation

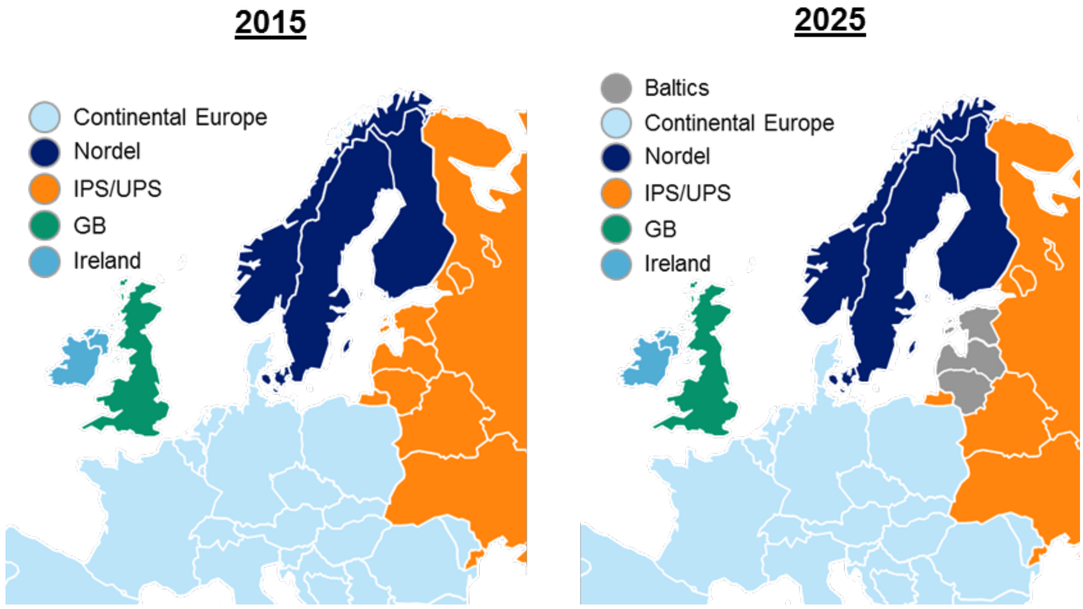
The Baltic and hence the Estonian electricity system is currently part of the BRELL synchronous loop[14]. This means that all automatic frequency control reserves are purchased and operated by the Russian TSO. Other BRELL members have an obligation to follow their planned exchange programs and if needed, use manually activated reserves.

As mentioned in chapter 1.1, one strategic goal of the Baltic states is to desynchronise from the IPS/UPS system. This is illustrated in Figure 10. A feasibility study “Integration of the Baltic States into the EU internal electricity market" performed by a Swedish consulting company Gothia Power launched in May 2012 analysed possible scenarios for connecting the electricity systems of the Baltic States with the European Continental Network for synchronous operation. The study analysed technical, legal and socio-economic aspects of the interconnection of the power systems. Although the study itself is confidential a public summary was released. The summary stated that one conclusion from the study is that synchronous operation with the Continental Europe synchronised power system (CE) is feasible, from a technical point of view, i.e. with respect to power flow, control and stability. The question of which region the Baltic states synchronise to (if any) is still open.

When the Baltic states desynchronise, there will be a need for automatic reserve products, primary and secondary reserves, and the capability to run the Baltic system in island operation mode in contingency situations before 2025.

[14] Transmission networks of the power systems of Belarus, Russia (Central and North-Western parts), Estonia, Latvia and Lithuania

Figure 10 – Synchronous electricity areas in Europe in 2015 and 2025



3.1.2 *Market integration of reserve provision with Baltic and Nordic markets*

A Nordic-Baltic balancing market feasibility study was commissioned to find conclusions, recommendations and a roadmap for balancing market cooperation between Baltics and Nordics targeting a common merit order in the future. The suggested Baltic-Nordic balancing market cooperation and development process may be split into four steps[15]:

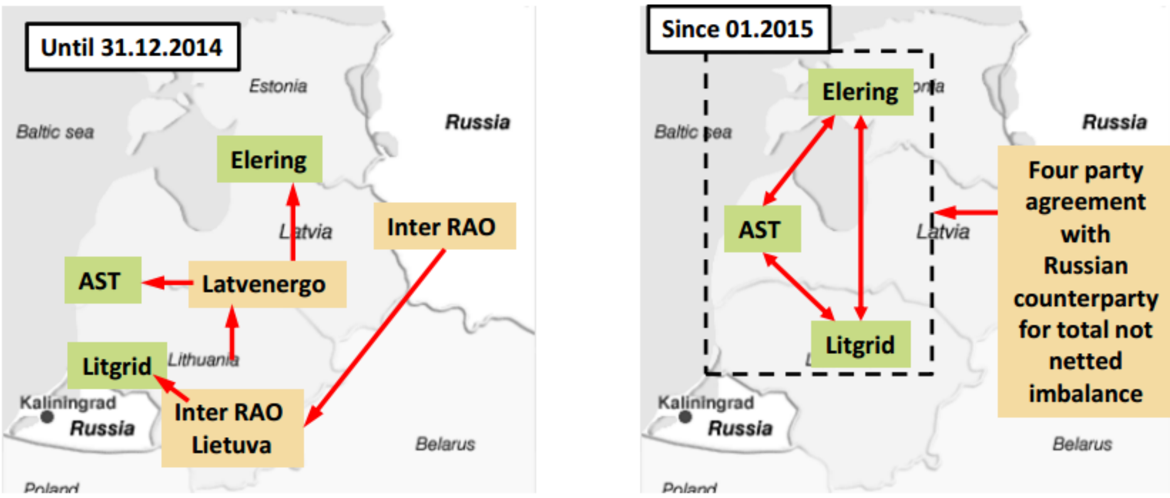
1. Development of current TSO-TSO assistance, testing new functions and extending TSO-TSO assistance;
2. Creation of common Baltic balancing area (incl. harmonisation of the balance management system principles and creation of common balancing market);
3. Establishment of deeper cooperation between Baltic and Nordic balancing markets aiming at common merit order; and
4. Creation of common Baltic-Nordic balancing market

Related to the second step, the Baltic electricity systems constitute a Baltic Coordinated Balance Area ('Baltic CoBa') as of January 2015, which is illustrated in Figure 11. This means that imbalance netting with the Russian system operator is done within the Baltic CoBa and not individually by each TSO. The process is expected to improve efficiency and reduce the volatility of imbalance prices in the Baltic states with early results for Estonia showing improvement in this respect with a reduction in balancing costs of 43% reported in January 2015[16].

[15] Elering AS, 2015. Cooperation between the Nordic and the Baltic power systems in Electricity Balancing. Available at: http://www.norden.ee/images/rohemajandus/info/energy2015/energy2015_IngridArus.pdf

[16] http://elering.ee/price-of-balancing-electricity-decreases-by-43-per-cent-in-january/

Figure 11 – Illustration of common Baltic CoBa scheme



Source: Elering

The centralized automatic frequency control by the Russian TSO means that the Baltic TSOs purchase currently only ‘slow’ reserves. These consist of emergency reserves and balancing power.

Emergency reserves are purchased for cases of N-1[17] violations, e.g. line tripping. According to the BRELL loop agreement, each Baltic TSO must maintain at least 100 MW of this type of capacity. Elering must reserve an additional 150 MW to be ready for tripping of the second interconnector to Finland, EstLink 2, when the import is at full capacity. To fulfil these requirements, Elering has recently built two reserve power plants, Kiisa AREJ 1 (140 MW) and Kiisa AREJ 2 (110 MW). Emergency reserve capacity may be bought from market participants or other TSOs only if it is not possible to receive sufficient capacity from the Kiisa power stations.

Balancing power is used to balance consumption and production in the Estonian electricity system at all times. Balancing power is offered to Elering by market participants, other Baltic TSOs and the Finnish TSO under terms and conditions of bilateral agreements. Rules and procedures of balancing power bidding and information exchange are not harmonized across Baltic TSOs.

The current balancing market rules in Estonia and the Nordics are presented in Table 3. In the Nordic market, the balancing power market is called the Regulating Power Market, RPM. The most important of these rules for DSR are the ‘minimum bid size’ and ‘full activation time’. In Estonia, the current 5 MW minimum bid size is more suitable for DSR than the Nordic 10 MW minimum requirement.

To promote DSR and renewable energy participation for this type of reserve provision, the Nordic TSOs have agreed to optimize the current RPM by implementing[18]:

[17] N-1 criterion means the rule according to which elements remaining in operation within TSO’s responsibility area after a contingency must be capable of accommodating the new operational situation without violating operational security limits

[18] eneginet.dk, 2014. Optimizing the existing Nordic mFRR market and investigating possibilities to exchange with other regions.

- Lower bid size from 10 MW (to 1 MW in the future with an intermediate step of 5 MW).
- Include a resting time mark in the IT system to allow for slower response resources like demand to participate.
- Electronic activation everywhere in Nordics (currently only in Denmark).
- Harmonize the period a bid is price setting.

The timing of these changes is still undecided. National pilot projects in the Nordic countries have started related to lowering the bid size from 10 MW to 5 MW.

Table 3 – Current Estonian and Nordic balancing market rules

Rule	Estonia	Nordic (Regulating power market)
Commercial model	Bilateral agreements	Market-based
Settlement rule	Pay as bid	Marginal pricing
Activation rule	Merit order	Merit order
Minimum bid size	5 MW	10 MW
Product resolution	1 hour	1 hour
Full activation time	10 min	15 min
Gate closure	45 min before operating hour	45 min before operating hour
Aggregated loads allowed to bid	Not mentioned	Yes

3.1.3 Penetration of wind generation

Estonia's renewable energy policy is mainly driven by its obligation under the European Union's Renewable Energy Directive to increase the share of renewable energy (RE) in gross inland energy consumption to 25% by 2020 from 16.6% in 2005. Estonia is on track to meet this obligation (15.3% in 2013). 13.2% of electricity was generated from renewable energy sources in 2013. Estonia supports renewable electricity by means of a premium, 5.37 c/kWh, added to the market price, and the amount of the subsidy does not depend on the market price of electricity. In 2014, wind generation was 576 GWh, which is just over 6% of the country's total electricity consumption.

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https://www.entsoe.eu/Documents/Network%20codes%20documents/Implementation/Pilot_Projects/140911_CBB_pilot_project_5_RPM.pdf

The ENMAK 2030[19] draft (published in February 2015) base case forecasts wind capacity to be 330 MW in 2020 compared to the current 300 MW, but in the “RE focus” case (50% RE electricity production by 2030), the capacity is estimated to be almost 1 GW by 2030. The European Wind Energy Association’s 2020 forecast for wind capacity in Estonia is 700 MW in the Central scenario. Estonia has two wind farm projects in early planning phase which could multiply the amount of wind capacity. For example, an offshore wind farm close to the island of Hiiumaa could have an aggregate capacity of 700 MW to 1,100 MW according to initial estimations.

DSR can be used to manage network constraints or defer/avoid network reinforcement investments. Under the current Estonian Grid Code, generators are responsible for network reinforcements if these are needed to enable connection of new power plants to the grid. In most cases capacity over 5 MW will be connected to the transmission grid (110 kV and above) and over 10 MW will be always connected to the transmission grid.

Wind curtailment is currently not seen as an issue on the transmission network in Estonia, but there are already some constraint management issues in wind farm connections in the distribution network. As an example, the DSO has been forced to limit the maximum connection capacity of one wind farm from 6 MW to 5.2 MW.

As the above-mentioned different forecasts and potential offshore projects show, the amount of wind capacity could increase significantly in Estonia and this could introduce more wide-scale network constraint issues. This is emphasized by the fact that the wind capacity is focused on hot spots in the western and northern coasts. According to Elering’s study[20], it is possible to integrate 900 MW of intermittent wind power capacity with a curtailment rate[21] of 0.1% with the condition that all the planned interconnections are built and all Baltic power plants participate in the balancing market. Grid reinforcement in the western part of Estonia (where the wind potential is the highest) would allow integration of more wind capacity into the system. There are currently constraints on the connection of wind generation in the regions of highest wind resource but transmission network investment over the next 10 years is expected to alleviate this.

In addition to domestic wind capacity, growing wind generation in interconnected Nordic countries has to be factored in when considering the effect of intermittency for the Estonian system. The Nordic countries have ambitious plans for wind generation and hence the flexibility provided by interconnectors could be restricted during low or high wind periods.

Contrary to many other countries, Estonia has not introduced priority dispatch for renewable power. Therefore, the system operator has flexibility and can curtail intermittent wind generation when it is necessary for safe and stable system operation.

3.1.4 Smart meter roll-out and Estfeed platform

Especially for small residential customers, smart meters are the primary way to control loads and allow them to offer DSR capacity to different markets. The smart meter roll-out is under way and is scheduled to be complete by 2016/17. This will allow DSR service

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[19] Estonian long-term energy development plan 2030+

[20] Wind Power in Estonia: An analysis of the possibilities and limitations for wind power capacity in Estonia within the next ten years. Prepared by Ea Energy Analyses for Elering OÜ, 2010.

[21] The yearly amount of energy curtailed from wind power plants

providers, such as aggregators, to pool loads and control them in a centralized way without the need to install separate load control systems.

Estfeed is a software platform (Energy Data Feed Platform) for integrating various data sources and to offer suitable services related to energy flexibility.

One of the first applications in Estfeed is Virtual Power Plant. The Virtual Power Plant allows small widely spaced energy producers to unite into one virtual energy producer managed via the application. This gives them a better access to the energy market. It should help owners of renewable energy devices to earn extra income and reduce their payback periods. The application is developed by the Estonian Renewable Energy Association.

Another application is electricity consumption aggregator. This application helps large and small energy consumers unite and become an active participant in the energy market as an aggregator. The application provides near real-time data of energy consumption and analysis of the data, which allows changing energy consumption patterns on the basis of price indications.

Both the smart meter roll-out and the Estfeed platform will work as market enablers in the future making offering DSR flexibility services easier directly by consumers and owners of distributed generation or by through third party service providers.

3.1.5 Electric vehicles

One of the common drivers for change in electricity systems is the widespread adoption of electric vehicles (EVs). EVs can cause local distribution network demand peaks when charged overnight, but also potentially contribute to system flexibility by providing DSR services.

Estonia initiated an Electromobility programme (ELMO) in 2011 which consisted of three pillars:

- Distribute 500 EVs to public sector actors;
- Provide subsidies (35 to 50%) to businesses, institutions and households for the purchase of an electric vehicle; and
- Build charging stations every 40 to 60 km.

As a result, there is currently a nationwide charger network with 165 quick chargers in Estonia and the number of EVs has reached 600 by January 2013. The subsidies were discontinued in August 2014 after which EV growth has been stagnant. Consequently, EVs are not considered a major driver or issue for network constraint management at the moment by market participants. For the purposes of this study it was agreed that EVs would not be a factor in the analysis. However, the existing charger infrastructure means that there could be potential for growth in EV adoption and they should not be omitted completely in the planning of future systems and regulation.

3.1.6 Expected consumer engagement and behavioural change

Estonian customers are currently not very motivated to provide DSR services and there is concern among the electricity market actors regarding the scale of DSR potential for certain services e.g. energy management. There is however some willingness for DSR participation which has been evident in previous DSR pilots and there have also been discussions on future provision of DSR services. The lack of available market data for system services and small base-peak price difference in the wholesale market have kept interest in DSR participation at a low level, thus far.

Participation can however be expected to grow as consumer awareness of DSR and different services it can offer grows. Completing the smart meter roll-out will lead to a larger potential customer base and the applications of the Estfeed platform will provide consumers an easier way to check what kind of benefits they could gain from providing their capacity to different market places.

3.2 Key stakeholder perspectives on DSR

As part of the study, key stakeholders have been interviewed about their perspectives in relation to DSR and to their perceived future role in the system. Insights from these interviews have been used to feed into the evaluation of the various DSR schemes to determine best fit options for Estonia. In this report, we do not refer to stakeholders by their names but instead refer to their respective roles in the electricity market.

3.2.1 Summary of stakeholder perspectives

Figure 12 presents the key drivers for each stakeholder group. The drivers are into split into internal and market factors which affect the demand and supply of flexibility in the short or long term.

To summarize, TSO and DSO expect to have some demand for flexibility provided by DSR to help operate their transmission and distribution networks in a variety of situations.

As already mentioned in chapter 3.1.3, the DSO has already been forced to curtail the maximum output of a wind farm due to local network constraints. In the long term, the DSO is expecting overloaded substations in all types of distribution network areas (rural, suburban and urban). Due to these constraint management issues, the DSO is already looking at different flexibility projects, such as energy storage.

For the TSO, the main application for DSR is manual frequency restoration reserves as long as the Baltic system is synchronized with the Russian system and automatic frequency control is managed by the Russian system operator.

Figure 12 – Summary of stakeholder drivers

Company	TSO	DSO	Supplier	Aggregator

Internal drivers	• Peak load and manual frequency restoration best applications for DSR
	• Reserve purchasing based on pay-as-bid, DSR resources potentially cheaper
	• Specific uses:
	  • Releasing interconnector capacity for exports
		• DSO will invest 100 M€ in security of supply (annually). DSR could help to defer or avoid some of these investments
		• Applications for DSR
		  • LV network constraint management (overloaded substations expected in rural, suburban and urban network areas by 2025)
		  • Planned outages
		  • Island operation in rural areas
			• Potential new revenue streams from offering system services to the TSO
			• DSR as part of portfolio management and risk management to reduce wholesale costs (but also revenues for generation)
			• Cost reductions for customers from peak price avoidance
			• Could impact generation fleet
				• Potential new revenue streams from offering system services to the TSO
				• Cost reductions for customers from peak price avoidance

Market drivers	• Baltic balancing market integration • Integration to Nordic markets • Synchronous operation with CE before 2025	• Wind power generation causes constraint management issues in some cases	• There is some willingness for DSR participation	• There is some willingness for DSR participation

A summary of the main barriers for the use of DSR is in Figure 13. These are primarily related to uncertainties about business models and roles and responsibilities of different market participants. This is due to the fact that the current regulation in Estonia is made for the conventional electricity system where generation is centralized and end-customers are passive participants who only consume electricity. The future system will introduce new roles in the electricity market, 3rd party service providers i.e. aggregators, and changes to the responsibilities of current market roles. The regulatory framework will define what revenue streams each actor can access and what interactions are required along the value chain.

Figure 13 – Summary of stakeholder views on barriers for DSR

TSO	• Unclear how to share balancing responsibility between aggregator, supplier and BRP*
DSO	• Role of the DSO unclear and consequently what kind of business models are applicable → regulatory framework does not support business case currently

Supplier	• DSR pilots were not successful due to small financial benefits and technical challenges
	• Overall market size for DSR not considered attractive enough
	• Roles and responsibilities still unclear (role of the DSO, balancing responsibility)
	• **Technical factors:**
	  • Lack of automated and modern loads
	  • DSR provision of residential loads hard to plan for, guarantee and control;
	  • DSR's relative position to generation (technical requirements)

Aggregator	• Business model uncertainties and data availability to calculate customers' business case the main barriers
	  • Elering does not have all necessary data currently available
	  • Penalties for not providing purchased capacity unclear

*There is no mention in the Estonian Electricity Market Act on how to handle balancing responsibility with 3rd party service providers

3.2.2 *Transmission system operator*

Manual frequency restoration reserve is the most suitable application for DSR currently as only "slow" reserves are used by Elering (before desynchronisation). DSR resources are potentially cheaper than conventional generation which could lead cost savings to the TSO and eventually to the end-consumers.

In the long run however, de-synchronization from the Russian system will create the need for new reserve products and the capability to run the Baltic electricity system in island operation in contingency situations. Preparations and pilot tests for this should start in a few years to ensure adequate reserve capacity when the Baltic TSOs are responsible for automatic frequency control in addition to manual balancing and emergency reserves.

Constraint management of the transmission network is currently not a major driver for flexibility except for a few certain individual issues. Currently, some interconnector capacity with Finland is reserved for balancing at times. Replacing this with DSR could release interconnector capacity for export. Even though wind curtailment has not been an issue so far in the transmission network, DSR could be used to avoid network reinforcements in the future when connecting new wind power plants in areas where the wind potential is the highest.

3.2.3 *Distribution system operators*

A DSO has already faced constraint management issues due to integration of wind generation. Due to these constraint management issues, the DSO is looking at different flexibility projects, such as energy storage and is initiating a research programme to evaluate future options for the use of DSR on the distribution network and take advantage of new technologies that are being installed.

Under the current regulatory framework, the role of the DSO is unclear in terms of local dispatching of resources and consequently what kind of business models are applicable.

Using flexible resources only for constraint management is unlikely to be a viable business case on its own, but the DSO should have access to other revenue streams as well, such as providing services to the TSO.

In the long term, the DSO is expecting overloaded feeders in their low voltage (LV) network due to increased consumption. This applies all types of networks: rural, suburban and urban. Flexibility provided by DSR could help to defer or avoid some of the network reinforcement investments.

Other possible applications include security of supply and island operation. Security of supply in this case means that DSR can help to reduce the effects of planned outages in the network due to e.g. maintenance work. Island operation is applicable in remote rural areas, where a long transfer line could be replaced by an island system with distributed generation, energy storage and DSR.

3.2.4 Suppliers

In this section we consider suppliers which are part of a vertically integrated energy company. This means that the same company also owns electricity generation which can be affected by competition from DSR.

The supplier interviewed for this study had experience from previous DSR pilots, which were not considered a success due to small financial benefits for the end-customer and some technical challenges. The scale of the potential DSR market is not considered attractive enough currently and roles and responsibilities of different market participants are still unclear. Examples of this are the role of the DSO in DSR activities and balancing responsibility in DSR activations.

Drivers for DSR for the suppliers include new revenue streams from providing system services to the TSO, using DSR as part of their portfolio and risk management to reduce wholesale costs, and offering cost reductions for customers by avoiding price peaks. On the other hand, the revenues for the generation fleet can be reduced if DSR can offer the same services at a cheaper price or if consumption is reduced when the price of electricity is high.

In its DSR pilot, one supplier found that lack of automated loads reduces the potential supply of DSR. The pilot focused on industrial loads. Residential loads have the biggest volume, but their DSR provision is harder to plan for, guarantee and control due to the large amount of small loads. Another technical barrier is the DSR's relative position to generation. Technical requirements of system services were written originally for generation and can be too onerous for DSR resources.

3.2.5 Aggregators

The drivers for aggregators are similar to suppliers but aggregators, which in the context of this project are considered to be independent third party service providers with no generation capacity, do not have existing customers and systems like the suppliers do from their electricity sales and trading activities.

One potential Estonian aggregator interviewed for this study mentioned that the main barriers, currently, are related to business model uncertainties and data availability, especially for providing DSR capacity to system services. The TSO does not have all the necessary data to calculate the potential value of flexibility of a potential DSR provider. Other uncertainties for calculating the customer's business case are the lack of clarity in the regulation with regards to balancing responsibility as well as lack of information about penalties if purchased capacity cannot be provided.

3.3 DSR applications and their relevance in Estonia

The potential uses for DSR in Estonia are listed in Table 4. These have been mapped onto the results of the stakeholder interviews.

Table 4 – DSR application and situations relevant to Estonia

Application	Situation
Modify demand to provide system services	DSR is used instead of generation and interconnector capacity to provide system services, e.g. frequency restoration reserve DSR is used to avoid peaking power plant investments
Shaving peak demand to avoid/defer network investment	TSO and DSO want to shift demand at the same peak Demand is shifted at the national level due to price signals and has an adverse effect on the local network
Modify demand to optimize wholesale costs	Suppliers drive price optimization through the use of DSR
Modify demand to compensate for a distribution network fault	Use DSR to avoid extensive network reconfiguration or the deployment of emergency generation to meet demand
Modify demand to accommodate low wind period	DSR is used to avoid the costs associated with alternative solutions to the problem
Modify demand to accommodate wind capacity	DSR is used to avoid deep[22] network reinforcements when installing wind capacity

In the following sections, the applications and situations are illustrated in a common framework describing:

- Problem statement i.e. the situation that DSR is addressing.
- Identification of the party that benefits from using DSR as well as the identification of whether DSR use involves savings on capital expenditure (CAPEX) and/or operating expenditure (OPEX).

[22] Includes the physical connection to the network and any upstream network reinforcements

- Identification of the initiating party (referring to the party who makes a contract with the DSR provider for their flexibility).
- Application level of DSR i.e. national or local.
- Problems and potential conflicts in the use of DSR.
- Relevance for Estonia (High, Medium, Low) and the timeframe over which the use of DSR becomes relevant.

The provider of DSR can be the end-consumer or an aggregator pooling the loads of several consumers.

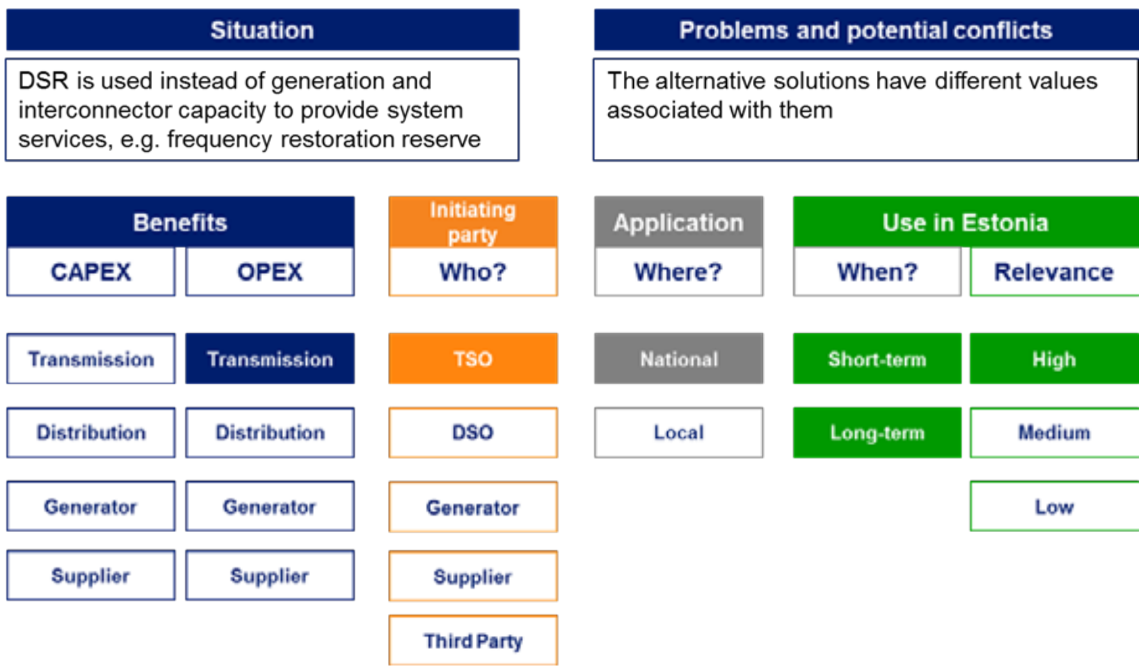
3.3.1 Modify demand to provide system services

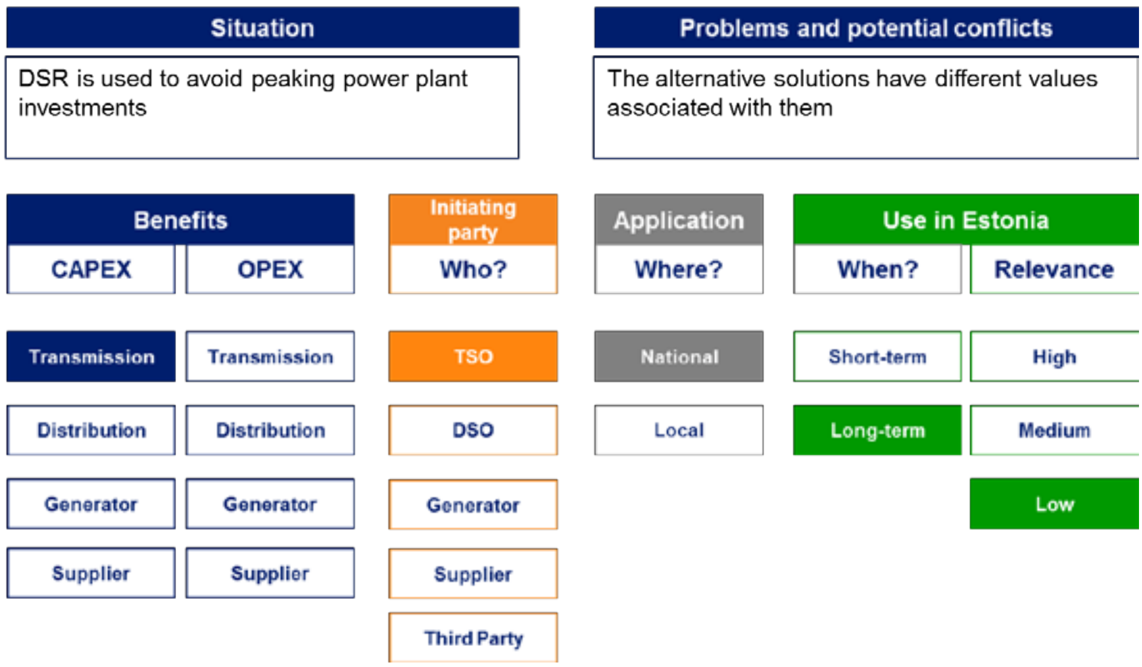
DSR is one of the possible providers of system services, along with conventional generation and interconnectors. The motivation to use DSR stems from it being potentially cheaper than the alternatives.

In Estonia, using DSR to provide manually activated frequency restoration reserve has been identified as a potential application in the short term. In the longer term, the demand for reserves will increase when Estonia desynchronizes from the Russian system. As a consequence, the relevance of DSR for reserve provision in Estonia is deemed high. Elering has just finished building two reserve power plants, the Kiisa plants, so the motivation to use DSR to avoid peaking power plant investments is deemed to be low at the moment, but with increasing reserve requirements under de-synchronisation, the requirement is likely to increase.

The schematics in Figure 14 highlight two situations where the TSO is using DSR for system services. The first focuses on OPEX savings due to DSR providing system services (avoiding use of existing plant to provide system services). The second schematic in Figure 14 focuses on CAPEX savings (avoiding investment in plant to provide system services).

Figure 14 – Modify demand to provide system services





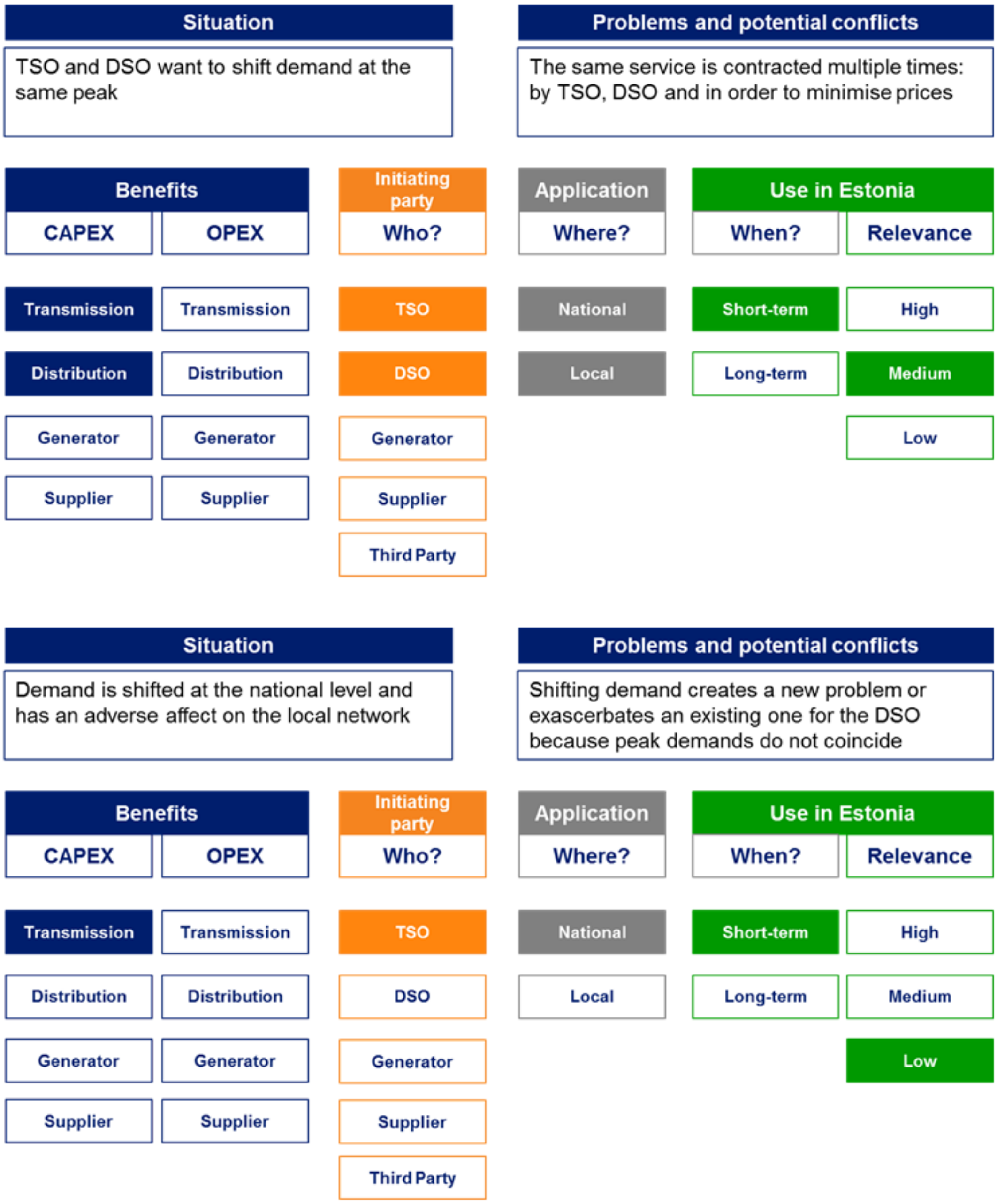
Source: Pöyry Management Consulting

3.3.2 Shaving peak demand to avoid/defer network investment

This includes two situations where the TSO, or the TSO and DSO, shave peak demand to avoid, or defer, network investment. The relevance to use DSR to manage network constraints is deemed high in the distribution network as one DSO is already experiencing constraint management issues and is looking at different flexibility projects. However, the relevance is low in the transmission network because DSR is not considered a feasible way to manage the biggest constraint issue in the transmission network, i.e. North-South transit flows.

In summary, the use of DSR by the DSO to avoid or defer network investment is deemed a relevant option by stakeholders and is discussed in more detail in chapter 4.2 of this report. The use of DSR to avoid or defer network investment on the transmission network was deemed less important and therefore was discarded for the quantification stage.

Figure 15 – Shaving peak demand to avoid network investment

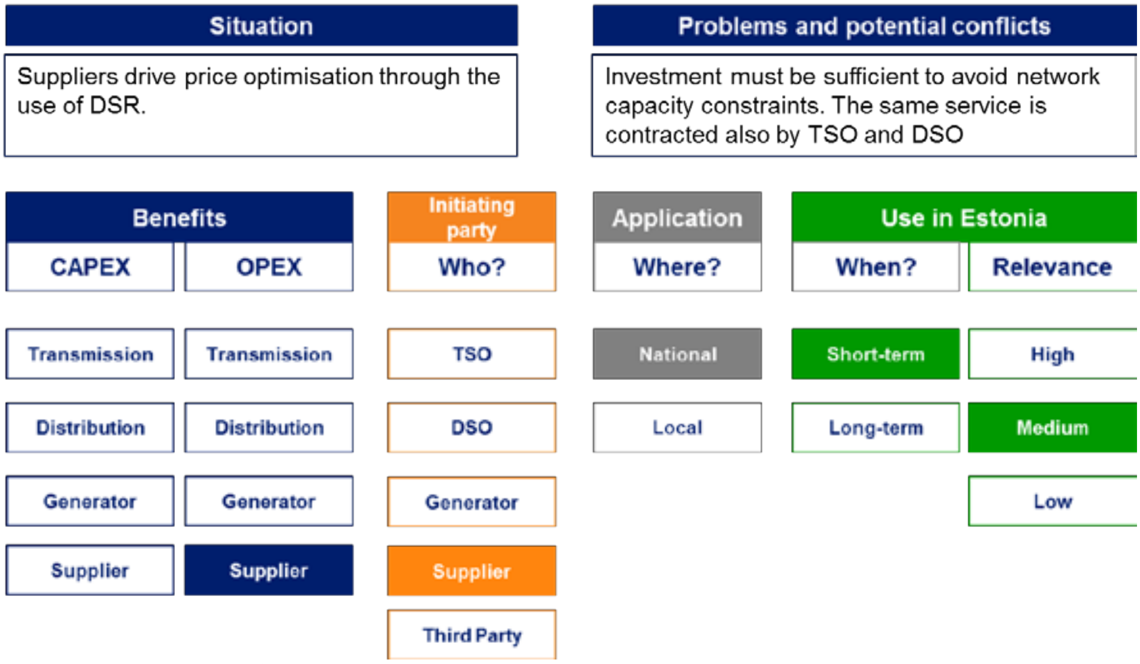


3.3.3 *Modify demand to optimize wholesale costs*

This refers to a situation where a supplier uses DSR for portfolio management to manage its wholesale costs by realigning their position between the day-ahead market and gate closure. The key issue is whether a supplier can achieve scale so that flexibility from DSR can have a meaningful impact on wholesale costs. Since flexibility by DSR is needed to manage e.g. wind forecast errors and unexpected load profiles, balancing and intraday markets would be primary market places for the supplier to use DSR for this purpose.

Wholesale cost optimization was seen as a potential use for DSR as part of the suppliers' portfolio management in the stakeholder interviews.

Figure 16 – Modify demand to optimize wholesale costs



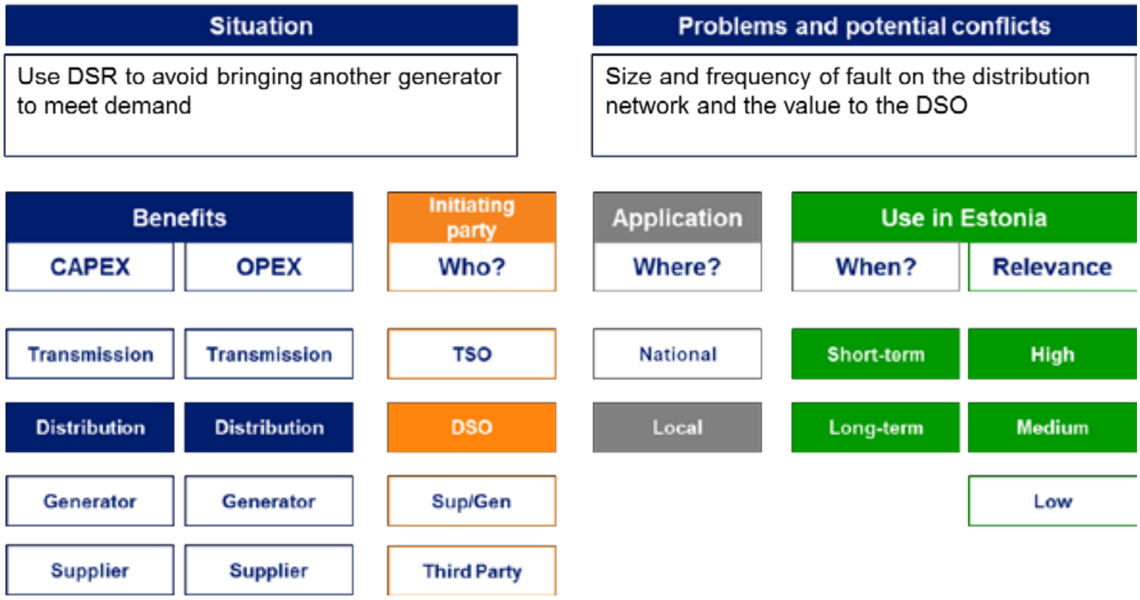
Source: Pöyry Management Consulting

3.3.4 Modify demand to compensate for a distribution network fault

This refers to a situation where a DSO uses contracts with DSR resources to manage a fault situation in the distribution network instead of the need for extensive network reconfiguration, using emergency generation to meet demand or having blackouts in parts of the network. Effectively this means using DSR to provide, for example, the redundancy in network capacity which might otherwise be provided by a duplication of assets (e.g. a second transformer at a substation site).

This is a localized service, usually required over a relatively short period of time so the value is high for the DSO for this purpose. The key issue is whether the average size and frequency of fault situations are large enough so that DSR could provide real value for the DSO as this is the type of event that may only occur a few times per year. However, the price signal associated with such an event could be significant.

Figure 17 – Modify demand to compensate for a distribution network fault



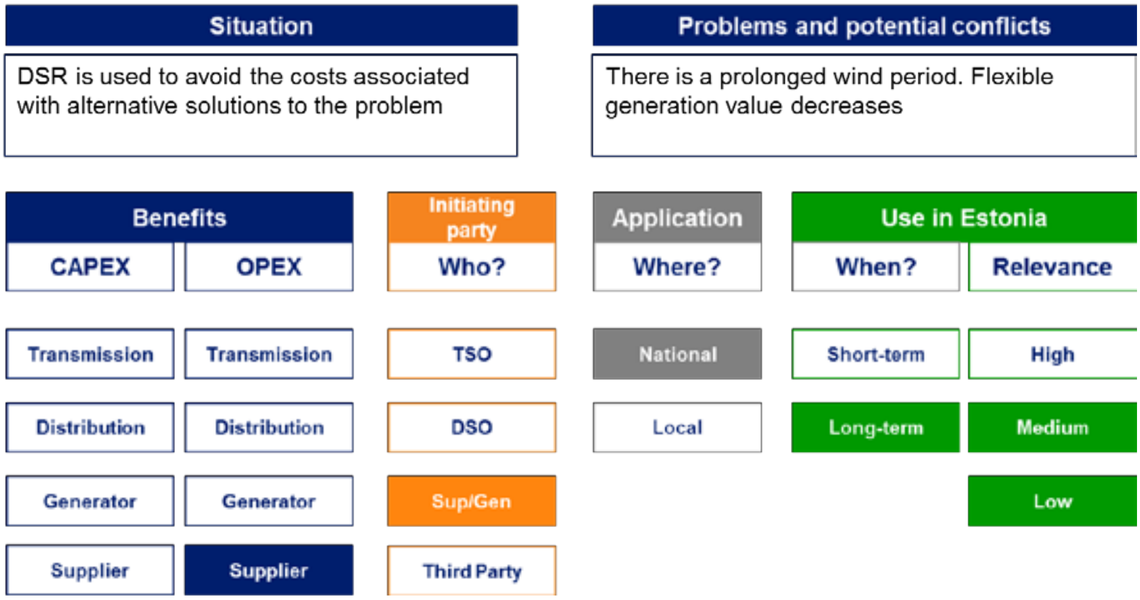
Source: Pöyry Management Consulting

3.3.5 Modify demand to accommodate low wind period

This situation is similar to wholesale cost optimization, but here instead of internal portfolio management, DSR is used to avoid costs associated with alternative solutions to accommodate low wind periods, i.e. replacing low wind production with flexible generation or imports.

This situation was not mentioned as a key issue in the stakeholder interviews as the significance of wind in the Estonian electricity market is limited currently and the increase in wind capacity is still uncertain. The relevance could increase if the amount of wind capacity increases significantly in the system. However, the level of interconnection and flexibility of the Nordic system was generally expected to be able to deal with these events.

Figure 18 – Modify demand to accommodate low wind period



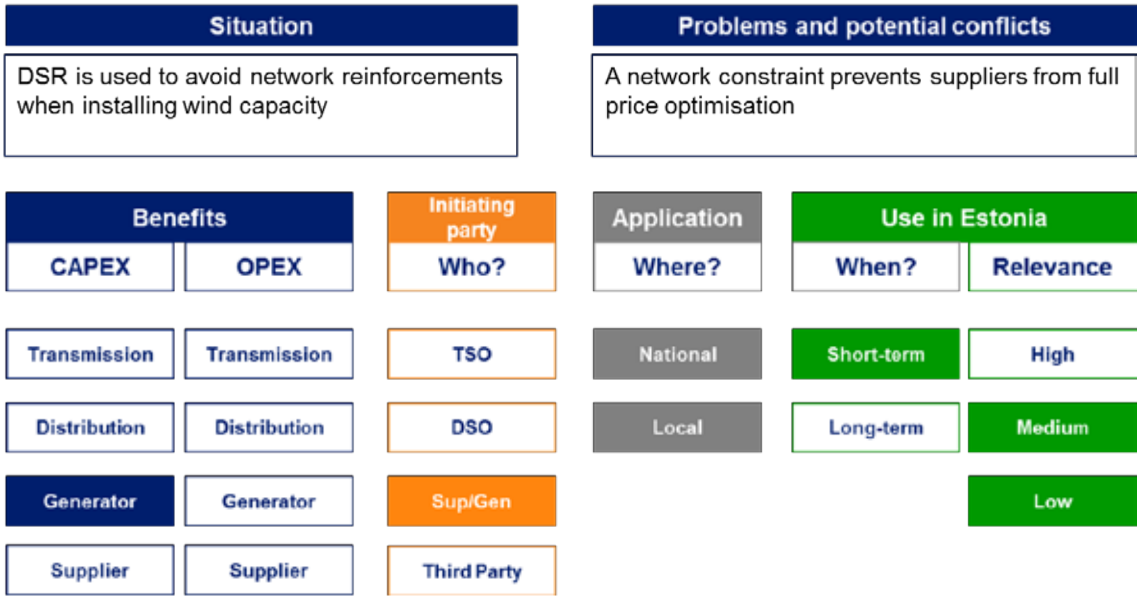
Source: Pöyry Management Consulting

3.3.6 *Modify demand to accommodate wind capacity in the network*

This refers to a situation where DSR is used to avoid possible network reinforcements when installing wind capacity. This means that at times of high wind generation, the local demand is correspondingly high. In Estonia, generators are responsible for network reinforcements if they are needed to accommodate new capacity. Constraint management due to wind integration is a current issue for a DSO. For the TSO, network constraints were not a major driver in the short term, but further adoption of wind generation (onshore and possibly offshore) in regional hot spots could cause constraint issues also in the transmission network.

There were issues identified in the stakeholder interviews when integrating wind power to the distribution network. This application was however not considered in the quantitative stage as its potential value is very case-specific depending on the network topology and limited to small wind farms because power plants of over 10 MW are connected to the transmission network according to the Estonian Grid Code. Most new wind power was expected to be connected directly to the transmission network. Wind power integration to the transmission network was not considered an issue by the stakeholders.

Figure 19 – Modify demand to accommodate wind capacity



Source: Pöyry Management Consulting

3.4 EU regulation and network codes

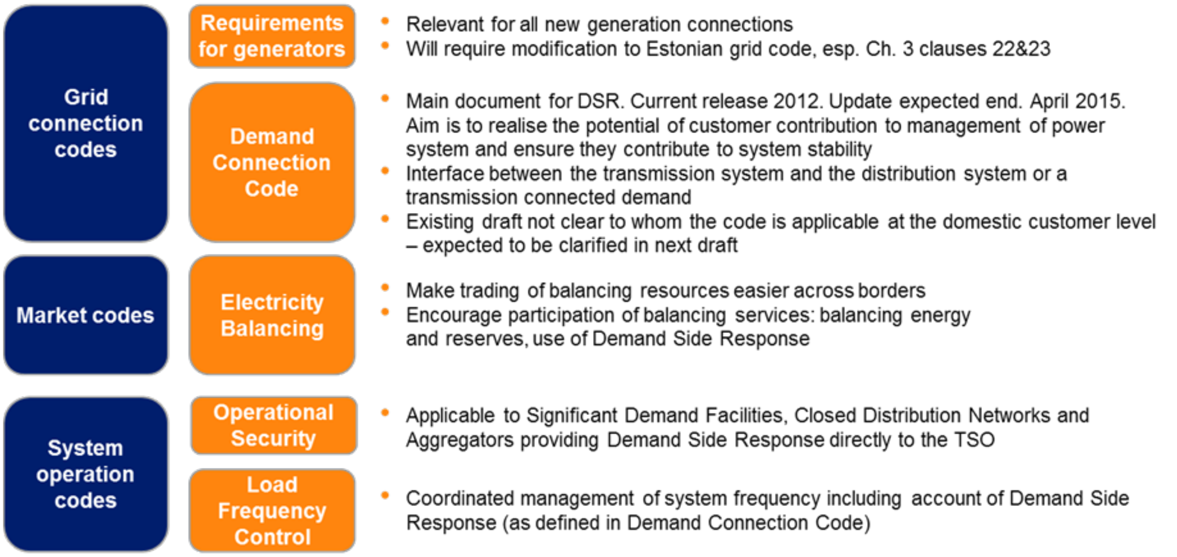
This section considers the EU Network Codes from a DSR perspective and considers where the existing Estonian Electricity Market Act and Grid Code would need to be updated to incorporate the Network Codes when the Baltic States synchronise with and join the EU electricity market.

Electricity market regulation in EU countries is directed by EU regulation. Regarding DSR, The Energy Efficiency Directive (2012/27/EU), part of the 3rd European Energy package, states that "Member states shall ensure the removal of those incentives in transmission and distribution tariffs that are detrimental to the overall efficiency (incl. energy efficiency) of the generation, transmission, distribution and supply of electricity or those that might hamper participation of demand response, in balancing markets and ancillary services procurement" (article 15, paragraph 4).

According to the same directive "Member States shall ensure that transmission system operators and distribution system operators, in meeting requirements for balancing and ancillary services, treat demand response providers, including aggregators, in a non-discriminatory manner, on the basis of their technical capabilities" (article 15, paragraph 8).

The 3rd Energy Package by the EU - introduced as law in 2011 - requires the development of European network codes. The EU network codes will drive market integration and amongst other things, set standards for DSR integration. These standards should then form the basis of national network codes. The network codes on grid connection, electricity markets and system operation are still a work in progress. A summary of relevant network codes to DSR and their contents is shown in Figure 20. Especially relevant is the draft network code on Electricity Balancing that "facilitates the participation of Demand-side Response including aggregation facilities and energy storage".

Figure 20 – Summary of relevant EU network codes



3.4.1 Grid connection codes

Requirements for Generators

The Requirements for Generators (RfG) are applicable to all new generation connections and the operational requirements are retrospective and apply to all generators. The code is relevant irrespective of a generator's participation in DSR. The RfG contains technical requirements which are cumulative across 4 types:

- Type A (under 1 MW): Basic requirements necessary to ensure capability of generation over operational ranges with limited automated response and minimal system operator control.
- Type B (1-50 MW): Wider range of automated dynamic response, with greater resilience to more specific operational events.
- Type C (50-75 MW): Refined, stable and highly controllable (real-time) dynamic response, aiming to provide principle ancillary services to ensure security of supply.
- Type D (over 75 MW or connected at ≥ 110 kV): Specific to higher voltage connected generation with an impact on entire system control and operation. Ensure stable operation of the interconnected network, allowing the use of ancillary services from generation Europe-wide.

In order to comply with the RfG, modifications to the Estonian Grid Code will be required, particularly to *Chapter 3 Technical Requirements Applied to Production Equipment*.

Demand Connection Code

The Demand Connection Code (DCC) recognises that whilst, historically, generation has provided the technical capabilities that contribute to system security, it is expected that demand users will play a more pivotal role in the future. The aim of the DCC is to realise the potential of customers' contributions to management of the power system and to ensure that they contribute to system stability.

The code contains requirements relevant to grid connected demand facilities and distribution systems, as well as requirements for equipment used by facilities that offer DSR to system operators connecting at distribution level. The code is applicable to new demand facilities and new distribution systems and not existing demand and distribution systems. The role of aggregators in optimising demand capabilities is recognised.

The DCC requirements cover frequency and voltage ranges and associated time periods for the Baltic synchronous area. There are requirements for the TSO to define the maximum short circuit current at the demand or distribution system connection points; requirements for reactive power import and export ranges; protection, control and information exchange requirements, and power quality requirements. Automatic under frequency control schemes are required and either automatic or control room initiated low voltage demand disconnection is an option for TSOs and TSO connected demand or the distribution system.

Demand-side response is considered in respect of services provided in the key areas of:

- Remote controlled active and reactive power control and transmission constraint management.
- Autonomously controlled frequency control and very fast active power control.

Demand facilities, which can be connected at any connection point on the transmission or distribution system, can offer DSR services to the TSO or DSO. The DCC specifies the requirements of the equipment to be used to provide the DSR service in respect of frequency and voltage ranges, low voltage frequency and demand disconnection. The DCC ensures that a facility providing demand-side response services cannot ignore or interrupt a request for demand-side response unless there is a contractual arrangement in place where the demand-side response is replaced by an alternative contribution.

There is a requirement for the provision of simulation models or information in respect of the DSR facility. Any demand facility connected below 1 kV can use an equipment certificate in this respect.

Operational notification for connection is detailed in the DCC and summarised in respect of documentation in Table 5.

Table 5 – Requirements for different demand-side response facilities

Applicability	Voltage of demand-side response connection	Requirement	Notification
Demand unit	Under 1 kV	Installation documents	
Whole facility	Over 1 kV	Equipment certificate	Energisation, interim and final operation notification. Limited operational notification
Demand unit	Over 1 kV	DSR unit document	

The Estonian Electricity Market Act and Grid Code do not deal explicitly with DSR and the DSR services identified by the EU DCC. The Estonian documentation does, however, address the need to balance the system in order to ensure supply security by considering regulating capacity. The Electricity Market Act defines regulating capacity as the capacity purchased under contracts entered into by the TSO and used by the TSO to increase or reduce generation and consumption in accordance with the contract.

Chapter 3 of the Act states that the TSO is responsible for ensuring the supply and balance of the system and that the TSO can require the modification of both generation and demand in accordance with the contracts for the purchase of regulating capacity as well as being able to mandate reduction in demand irrespective of any contract if system security requires it. Chapter 4 of the Act is concerned with maintaining security of supply and contains provision for the TSO to utilise demand-side measures if the reserve capacity cannot be met, or as necessary to promote integration of low carbon technologies in the initial stages of their development.

The Estonian Grid Code, *Chapter 2 Supply Security of the System*, Paragraphs 7-9 consider system security and state that the TSO may request measures to provide security of supply and may switch off demand in emergency situations, automatic load shedding (under frequency and voltage protection) and restoration is also detailed.

Modifications to the Estonian Electricity Market Act and the Grid Code would be needed to develop demand-side response from the existing mandatory last resort requirements towards encouraging the provision of the range of DSR services identified in the DCC. Adequate provisions would also be required at the same time to safeguard the TSO by specifying the data and operational requirements in line with the DCC.

High Voltage Direct Current Connection (HVDC)

The HVDC Code covers management of HVDC lines and their connections and is intended to co-ordinate HVDC system development to ensure HVDC contributes to system security, enable off shore wind farm connection and facilitate HVDC technology competition. The code content does not cover HVDC involvement in DSR.

3.4.2 Market codes

Capacity Allocation & Constraint Management

The Network Code on Capacity Allocation and Constraint Management will be the first network code to become law (expected mid 2015) and is applicable to Transmission System Operators, National Regulatory Authorities, the Agency, Designated Nominated Electricity Market Operators and Market Participants. The code deals mainly with day ahead and intraday markets and managing cross border constraint and is not directly relevant to DSR.

Forward Capacity Allocation

The Network Code on Forward Capacity Allocation is applicable to Transmission System Operators, National Regulatory Authorities, Allocation Platforms and Market Participants. It is designed to manage risk associated with cross border electricity trading and deals with the forward market.

Electricity Balancing

The Network Code on Electricity Balancing is applicable to the TSO and Market Players and aims to develop a European balancing market where the TSO buys balancing energy.

The code aims to make trading of balancing resources easier across borders and encourage participation of balancing services (balancing energy and balancing reserves). The Code allows for use of DSR and the use of aggregation in the provision of balancing services and states that the pricing method used in the procurement of Balancing Capacity shall strive for an economically efficient use of DSR.

Electricity balancing responsibility is covered in Chapter 4 of the Estonian Electricity Market Act and Chapter 8 of the Grid Code. Aggregators are not presently considered as Market Participants in the Act and DSR and the role of aggregators is not specifically covered. The Act will need to be updated to incorporate the requirement of the Network Code on Balancing in respect of DSR.

3.4.3 System operation codes

Operational Security

The code is concerned with Operational Security as the primary goal of the TSO and the requirement for TSOs to coordinate to ensure security of European electricity supplies. It defines the data exchange requirements and testing and analysis responsibilities between the parties:

- TSO-TSO.
- TSO-DSO.
- TSO/DSO-generation.
- TSO/DSO-demand.

The code is applicable to Significant Demand Facilities, Closed Distribution Networks and Aggregators providing DSR directly to the TSO. Demand participating in DSR which is connected to the transmission system, significant demand connected to the distribution system or demand managed by an aggregator has to inform the TSO about the minimum and maximum power to be curtailed and communicate the active and reactive power in real time (near real time on behalf of all demand in the case of an aggregator).

As noted previously the Estonian Electricity Market Act states that the TSO can demand reduction in consumption to ensure security of supply. The Act states that the TSO has the right to require the submission of data from the market participants and Sections 42 and 42(1) of the Act are concerned with the Grid Code and information exchange. Therefore it may be more appropriate to add the Operational Security Code DSR data management and real time power requirements to the Grid Code rather than amending the Electricity Market Act.

Operational planning and scheduling

The Network Code on Operational Planning and Scheduling is applicable to TSOs, DSOs and Significant Grid Users. The Code is concerned with the efficient functioning of the internal electricity market, to ensure regional integration and system security. The Code covers generation and demand planning, transmission security planning, and TSO cooperation, to provide a common approach to assessment of operational security. The Code refers to the Operational Security Code in respect of DSR data requirements which have been discussed above.

Load Frequency Control and Reserves

The Network Code on Load-Frequency Control and Reserves (NC LFCR) is applicable to TSOs, Reserve Connecting DSOs, Providers' Power Generating Modules and Demand

Facilities. The Code is concerned with coordinated management of system frequency including account of DSR (as defined in Demand Connection Code) to ensure security of electricity supply. The Code provides transparency of rules for interaction between TSO, reserve providers and cross border exchange and is a foundation for the balancing market.

3.5 Other regulatory issues related to the implementation of DSR

3.5.1 The role of the DSO

Existing DSO responsibilities in Estonia

According to the Estonian Electricity Market Act, the DSO currently fulfils the conventional role of the DSO and is regulated by a conventional CAPEX model (justified profitability is based on the weighted average cost of capital and the regulated assets[23]). Below are listed some selected parts from *§ 65.Provision of network services* of the Estonian Electricity Market Act, which are considered 'conventional DSO responsibilities' (list numbers refer to the original numbering in the legislation):

> (1) A network operator shall provide the following network services to the consumers, producers, line possessors or any other network operators within its service area:
>
> > 1) on the basis of a corresponding request, **connection to the network** at the connection point of any electrical installation which conforms to the requirements and which is located in its service area.
> >
> > 2) on the basis of a corresponding request, amendment of the consumption or generation conditions.
> >
> > 3) enabling a network connection to be used at the connection point.
> >
> > 4) **transmitting electricity** through its network to the connection point or from the connection point.
> >
> > 5) ensuring the **installation of a metering device** conforming to the requirements of legislation to determine the amounts of electricity transmitted through its network.
> >
> > 6) ensuring the collection and processing of metering data.
> >
> > 7) provision of supplementary services directly related to the network services specified in points 1-6 of this subsection.
>
> (2) A network operator shall observe the principle of **equal treatment of market participants** when providing network services.
>
> (3) A network operator has the right to refuse to provide network services if:
>
> > 4) the network of the network operator **lacks the necessary transmission capacity** for the provision of network services.

[23] Uniform Methods for Calculating Electricity Network Charges, Estonian Competition Authority, 2014

(6) Establishment of the conditions for the **reduction of distribution charges** shall be based on the **duration of electricity interruptions** caused by failures.

Future outlook

There is a general consensus that with the introduction of new technologies at the distribution network level (such as smart meters and demand-side response) the role of the DSO will need to evolve.

The Council of European Regulators (CEER) published a consultation paper on the future role of DSO in December 2014. Activities relevant for the scope of this study can be found in Figure 21. To summarize, dispatching local resources and last resort supply are considered activities that are potentially allowed for DSOs if there is no competition or special reasons require it. This could open up a way for the DSO to use e.g. DSR or energy storage to manage network constraints (i.e. constraint) or security of supply issues. Another possible responsibility for DSOs is to transmit load control messages from suppliers or aggregator.

Figure 21 – Future role of DSO

CEER analysed activities (1) on DSO involvement	Core activities	Potentially allowed²	Forbidden activities
Penetration of RES plants and demand for flexibility			
• **Local dispatching of local resources** • Using batteries and other accumulation systems for congestion resolution		✓	
Activities in which the DSO should not be involved			
• Energy production • Energy supply			✓
• Exception to allow bargaining temporary local production to grant supply continuity • **Exception as last resort supply of electricity**		✓	
Activities related to retail market liberalization			
Interaction with suppliers	✓		
• Activities for the protection of suppliers' revenues (eg . Final consumer disconnection in case of arrears) • DSO activities on request of suppliers (e.g . switches) • Commercial data management related activities		✓	
Management and collection of data on consumption			
Management and collection of data for commercial purposes		✓	
Management and collection of data for security purposes	✓		

Source: "The Future Role of DSOs A CEER Public Consultation Paper" – CEER C14-DSO-09-03

1) Council of European Energy Regulators

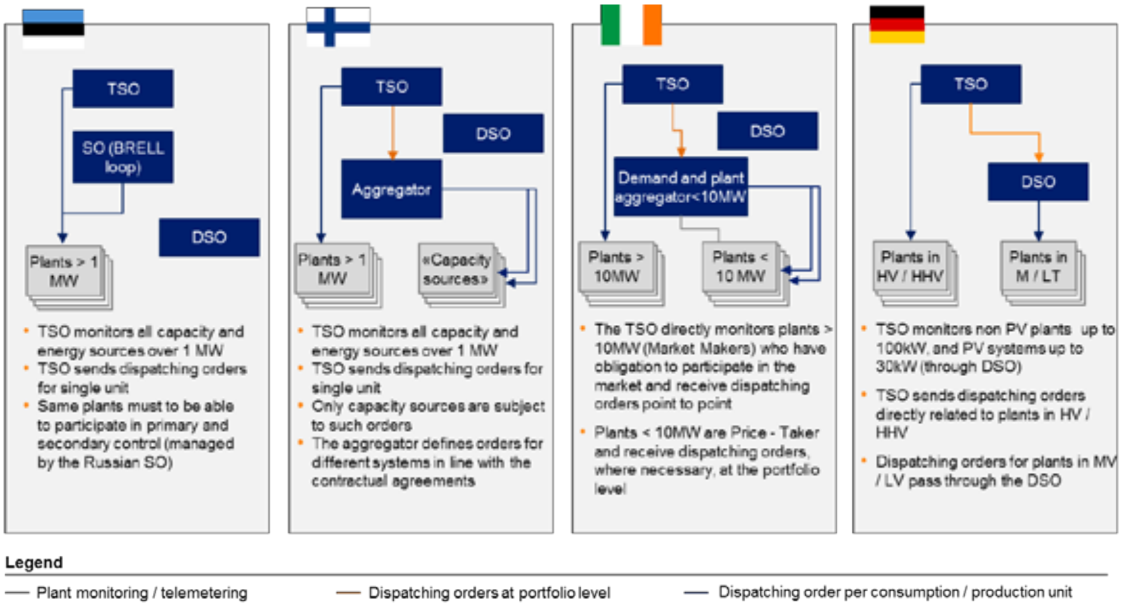
2) These activities are permitted only where there is no competition or there are special reasons that require the involvement of the DSO . The CEER reserves to deepen in a subsequent study which of the activities identified fall into these categories and are therefore effectively permitted and which are not

3.5.2 Interaction between the DSO and TSO

In addition to the issues mentioned above, the fact that the DSO could be responsible for dispatching resources on its network raises the question of interaction between the DSO and TSO.

Figure 22 presents four different models of TSO-DSO interaction in balancing activities in Estonia, Finland, Ireland and Germany. All these models attribute a passive role to the DSO, but it is questionable if this role will change in the future and if the DSO will get a more active role. Currently, the Estonian balancing regulation mentions that the TSO has to have a chance to monitor directly all sources, which have a bilateral contract with them to provide balancing services.

Figure 22 – TSO-DSO interaction in balancing activities in selected countries



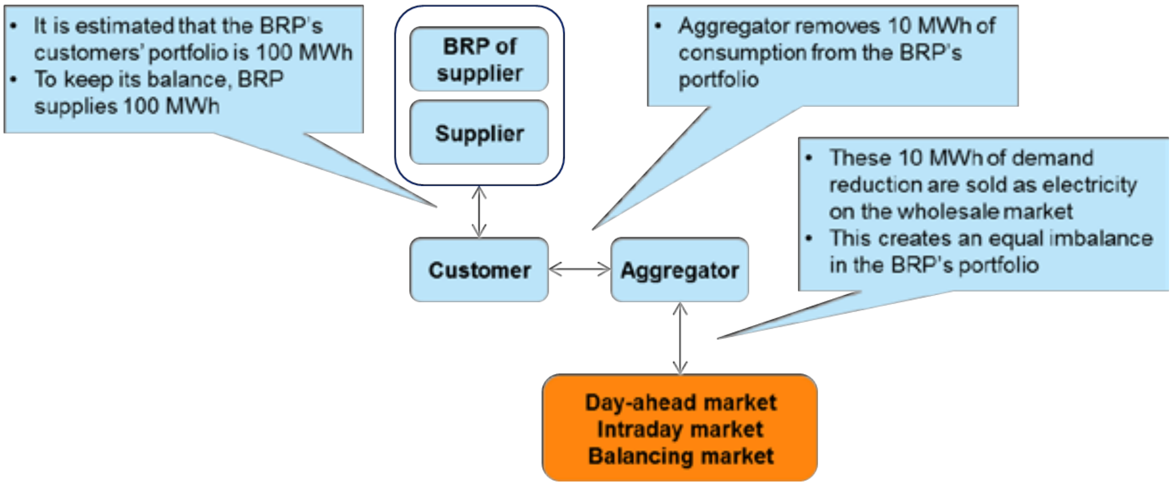
Source: Pöyry Management Consulting

3.5.3 *Interaction with aggregators*

A key question related to the aggregator model is how balancing responsibility is divided between different stakeholders. In Estonia, the balance provider, i.e. the balance responsible party (BRP) is responsible for the balance of the market participants in its open supply chain.[24] In other words, it is the balance provider's responsibility to ensure that the amounts of electricity bought from or put into the grid by market participants in its balance area and the amount of electricity sold or taken out of the grid in the same trading period are in balance. The imbalance issue caused by an aggregator is illustrated in Figure 23.

[24] Elering website, available at http://elering.ee/balance-agreement/

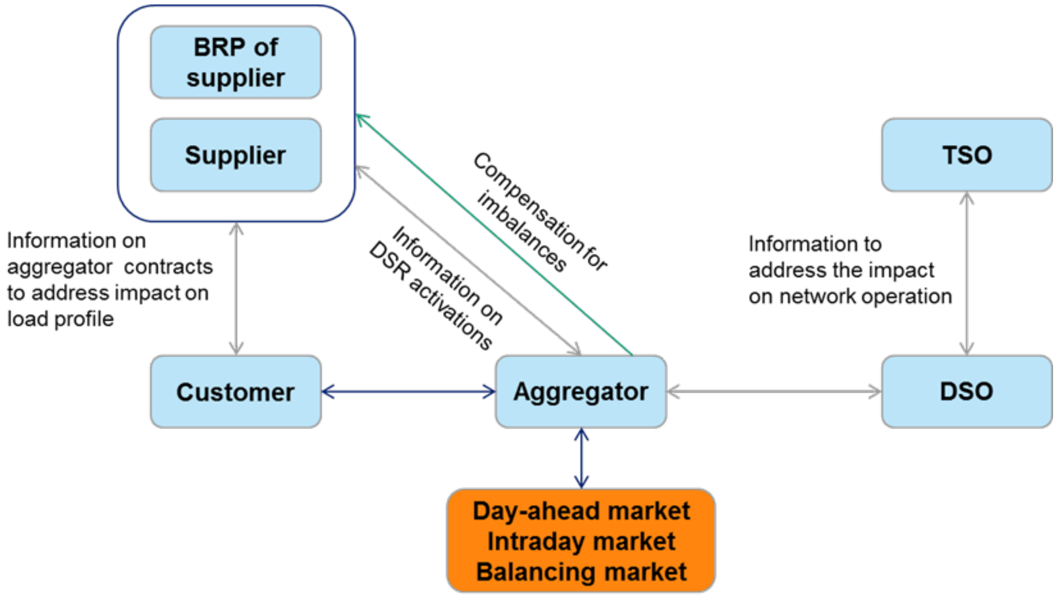
Figure 23 – Imbalance caused by aggregators



Source: Pöyry Management Consulting

Contractual and operational arrangements between 3rd party aggregators and other market parties are needed to address the impact of DSR contracts and activations. These arrangements and what they contain are illustrated in Figure 24. The supplier and the BRP can use the information of the customer's DSR contracts to assess their impact on the customer's load profile.

Figure 24 – Necessary links to address aggregator impacts



Source: "Designing fair and equitable market rules for demand response aggregation" – EURELECTRIC

There is currently no mention in the Estonian Electricity Market Act on how to handle balancing responsibility with 3rd party service providers, i.e. aggregators. Given the characteristics of the Estonian demand-side resource (section 4.1 Table 6) the aggregator model will be required to unlock the potential. Models in other countries include:

- Direct compensation of a BRP by the aggregator at a regulated price (France).
- Bilateral agreements with the BRP or becoming the customer's BRP (e.g. Norway).

- Aggregators can operate as service providers for a supplier (Finland).
- Aggregators have a direct access to customer and BRP's imbalances are not compensated (Great Britain).

To conclude, key questions to consider include:

- In which markets, if any, can aggregated load participate?
- Can the aggregator act without permission of the BRP?
- Are imbalances involved?
- What information is needed from aggregator to BRP in advance and in real time?
- What compensation is paid, and at what price?
- What rights are the customers deemed to have over their option to select their service provider?

3.6 Business models and contracts for DSR

3.6.1 Business models for DSR

Section 3.3 highlighted the possible alternative uses of DSR in Estonia and the various stakeholders involved in the different DSR actions. The actions of the stakeholders will need to be driven by the commercial framework around which the following objectives are met[25]:

- Making sure that industry see the value in DSR.
- The value of demand-side response services needs to be effectively signalled to customers.
- Customers need to be aware of and able to access the opportunities associated with DSR.

The commercial framework consists of different routes to market and price signals. Route to market refers to the contractual framework between the party contracting for DSR services and the party providing those services, be it e.g. bilateral agreements or market-based auctions. Price signals refer to how different parties convey the value of DSR services to DSR providers. This can mean static or dynamic tariff structures or dispatching signals to curtail load manually or automatically.

A specific combination of route to market and price signal is effectively trying to strike a balance between simplicity of scheme, which encourages customer engagement, and value capture from the services DSR can provide. Ideally, you would have bespoke contracts with each customer according to their technical capabilities and potential for flexibility, but this is not practically feasible except for maybe the largest consumers. This is especially true for DSR given the diverse range of consumption patterns across different potential customer types and the varying ability and willingness to change these patterns. Examples of simple routes to market are different time-of-use tariffs offered by the TSO, DSO or the supplier

[25] Ofgem, 2013. Creating the right environment for demand-side response. https://www.ofgem.gov.uk/ofgem-publications/75245/creatingtherightenvironmentfordemand-sideresponse.pdf

The following sections present routes to market, price signals, and customer access and engagement from the point of view of different initiating parties procuring DSR services. Aggregators are considered as DSR service providers and are thus not considered here.

3.6.2 Transmission system operator

System services

For contracting system services, the TSO generally has two optional routes to market:

- Bilaterally contracted with large energy-intensive customers.
- Market-based auctions where all eligible providers can bid their capacity.

Regarding reserves, – primary, secondary and tertiary – in both of these models, compensation for the customers consists typically of availability and utilization fees. Availability fees are on €/MW,h basis, i.e., how much capacity the service provider commits to hold for an agreed period of time. Utilization fees are then on €/MWh basis, i.e., based on energy usage of the committed capacity. Depending on the reserve type, activations occur frequently or just a few times a year. Tertiary reserves are typically divided into balancing and emergency reserves. In the case of DSR, mainly large industrial customers with interruptible contracts are eligible for emergency reserves apply mainly to large industrial customers with interruptible contracts.

In the case of bilateral contracts, price signals for reserve holding are based on an agreed fee. The contracts can include time limits, which the service provider commits to hold reserve, e.g. 7,000 hours per year. In a market-based setup, reserves are purchased based on a merit order and the availability fees are then typically defined on a pay-as-bid or marginal pricing basis. Auctions are held on fixed intervals for a pre-defined minimum bid resolution. For example, a TSO can decide to have auctions once a day for one-hour bidding slots. The availability fees, i.e. the price of reserve holding, are then decided separately for each hour based on a merit order curve.

Compensation for utilizations is based on a pre-defined fee, market price of electricity or bid separately. An example of the latest option is in use in Norway where the TSO uses a two-tier auction setup with separate bids for availability and utilization. The activation signal from the TSO is a manual dispatch request to the contracted provider or an automated response. As an example, in Finland the utilization price is the market price of electricity in the frequency controlled normal operation reserve (FCR-N) and automatic frequency restoration reserve (FRR-A) markets. For frequency controlled disturbance (FCR-D, on-off model) and fast disturbance reserves, the utilization price is a fixed €580/MWh.

In both routes to market large customers can participate directly if they fulfil the technical requirements to provide system services. Smaller customers, who usually do not fulfil at least the minimum size requirement, require an aggregator pooling the capacity of several customers.

Regarding consumer engagement, understanding the penalties for non-delivery, different types of service and bilateral or auction-based tender process is challenging as shown in the international case reviews. In addition, the two-tier compensation structure consisting availability and utilization fees makes comparing returns with other routes to market challenging. This all makes the role of aggregators or other third-party service providers more crucial to increase customer engagement.

Transmission system charges

For constraint management in the transmission network, the TSO generally has two optional routes to market:

- Static Transmission Use of System (TNUoS) tariffs
  - Customer access: direct contracts with large energy-intensive customers connected to the transmission network.
  - Costs passed through distribution system operators or suppliers (depending on the market setup).
  - Price signal is communicated via contracts.
  - Customer engagement: the role of transmission cost can be rather small of the consumer's electricity costs.
- Dynamic tariffs, e.g. critical peak pricing
  - Customer access: same as for static tariffs.
  - Price signal is reliant on smart metering or other communication means to communicate prices.
  - Customer engagement: ex-post nature, i.e. critical peaks are defined after the event, of reward makes it difficult to compare with participation in other markets.

Regarding customer access, direct contracts are limited to a small group of large industrial customers. If costs are passed through DSO/supplier, TSO is dependent on them on charges being visibly to the customers.

Relevance and barriers in Estonia

System services are relevant when desynchronisation occurs as Elering is then responsible for procuring all types of reserve. Currently, Elering has a mechanism for bilateral contracts in the mFRR market. There has been no DSR participation thus far in that market. Estonia has limited industrial DSR potential (see Table 6) meaning that aggregators are needed to increase the scale of potential DSR for system services.

Market-based auctions require changes to current system service purchasing mechanisms, especially if different types of reserves are shared among Baltic states after desynchronisation.

Static TNUoS tariffs have limitations as a means to signal the value of DSR although their simplicity and structure makes it easier to engage customers than with interruptible contracts. There is no limitation in Estonia on how the TSO can set up their tariffs as long as the basis for network charges is transparent and in compliance with the principle of equal treatment and the DSO does not exceed their justified return on capital allowed by the regulation[26]. In addition, the network charge shall not depend on the location of the market participant.

3.6.3 Distribution system operator

For constraint management in the distribution network, the DSO generally has two optional routes to market:

- Static Distribution Use of System (DUoS) tariffs
  - Direct contracts with customers or costs passed through suppliers (depending on the market setup).
  - Price signal is communicated via contracts.
  - Customer access: reliant on supplier if distribution costs are passed through supplier, otherwise straightforward.
  - Customer engagement: easy to engage as charges are clearly structured.
- Customers, individual or aggregated, have interruptible contracts to manage critical peak and/or fault situations
  - Requires direct control of load directly or via an aggregator.
  - Price signal is reliant on smart metering or other communication means to communicate prices or alternatively based on contracted fees.
  - Customer access: direct contracts limited to a small group of 'significant' customers in the distribution network, otherwise reliant on aggregators to pool loads.
  - Customer engagement: availability fees are straightforward to assess, ex-post nature of utilization fees makes it difficult to compare with participation in other markets.

Relevance and barriers in Estonia

Constraint management is relevant in specific network areas according to the stakeholder interviews. This means that bespoke contracts with direct DSO control are required. In addition, potential customers have to be located in suitable parts of the network where the DSO is facing constraint issues.

As illustrated by Figure 54, Estonia has limited industrial DSR potential meaning that aggregators are needed to increase the scale of potential DSR available to the DSO. In the stakeholder interviews, it was unclear how the current regulation allows the local dispatching of DSR for DSOs. There is no mention in the current Electricity Market Act or Grid Code about DSO using DSR for constraint management or other uses. This means that regulatory change is required to enable DSOs to capture value from local dispatching of DSR.

Static DUoS tariffs have limitations as a means to signal the value of DSR for DSOs although their simplicity and structure makes it easier to engage customers than with interruptible contracts. Similarly as for TSOs, there is no limitation in Estonia on how the DSO can set up their tariffs as long as the basis for network charges is transparent and in compliance with the principle of equal treatment and the DSO does not exceed their justified return on capital allowed by the regulation. The network charge shall not depend on the location of the market participant.

[26] Division 3, Charges for network services, Estonian Electricity Market Act

The current regulatory framework does not incentivise DSOs to decrease operating expenses as the justified profitability is based only on the regulated asset value and operating expenses are passed through to the customers. In the case of infringement of quality requirements for the provision of network services, i.e. interruptions, the DSO is required to reduce network charges. This gives an incentive for the DSO to adopt mechanisms increasing the security of supply in the distribution network, such as interruptible contracts to manage critical peak situations.

3.6.4 Supplier

A supplier's primary route to market is through the use of a range of static and dynamic Time-of-Use (ToU) tariffs which could be combined with direct load control. As for TSOs and DSOs, the price signals in static tariff structures are communicated via contracts and dynamic tariffs are reliant on smart metering or other communication means (home displays etc.) to communicate price signals. Customer access depends on what suppliers are offering, e.g. does the customer have the necessary communication means and automatic loads to respond to dynamic price signals. Depending on their form, ToU tariffs range from easy for customers to engage with, to difficult.

Relevance and barriers in Estonia

In the stakeholder interviews, portfolio and risk management were seen as potential DSR uses for suppliers. Due to the small base-peak price difference in the wholesale market, the customers' motivation to participate in DSR schemes has been limited thus far.

Smart meters will enable the required measurement for ToU tariffs and provide a channel to communicate price signals if dynamic tariffs are used. For automatic load control, co-operation with DSOs is required to transmit load control signals via smart meters.

3.7 Technical considerations for reserve provision by DSR

From the technical perspective, it is challenging for DSR to provide secondary reserve as the consumer / generator needs to be able to dynamically alter its demand with very short notice. However, there are many examples, such as Enernoc in Germany, where DSR has been successfully used for secondary reserve provision. A technical review would need to be carried out to verify the ability of Estonian DSR to meet secondary reserve requirements.

On the other hand, DSR is well suited to provide Primary Control Reserve and Tertiary Control Reserve following loss of an interconnector or generator with the following qualifications:

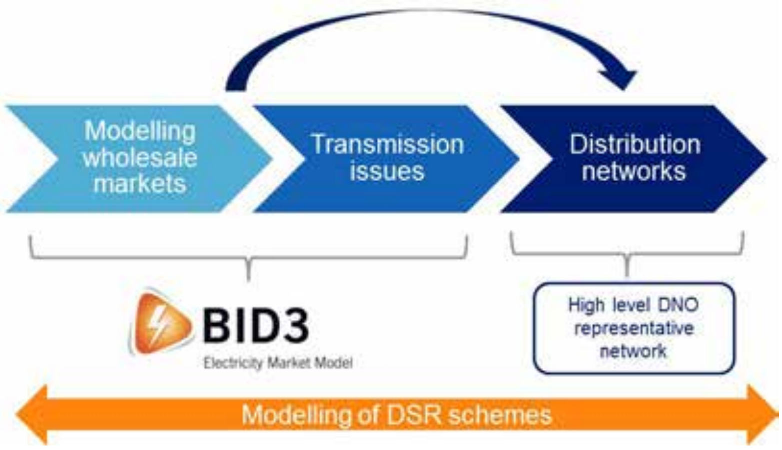
1. For DSR to be acceptable to the DSR customers for provision of Primary Control Reserve the under-frequency activation limit would have to be set such that there are not many incidents of activation a day, especially for customers with no storage such as refrigeration. Typically more than 1- 5 interruptions a week become a problem for the customer.
2. Tertiary Control Reserve from DSR is typically limited to peak times when there is not enough Secondary Control Reserve available and where the activation time is limited to 2 hours. Tertiary Control Reserve could be provided by large industrial consumers who can be interrupted from the Transmission system. In Estonia, sufficient demand reduction might be challenging to obtain from directly connected transmission customers and investigation should be undertaken to establish if that level of demand reduction could be obtained from a variety of smaller customers.

Obtaining DSR from lots of smaller consumers is likely to require the use of an aggregator.

4. QUANTITATIVE ANALYSIS OF DSR OPTIONS

In order to understand the usage patterns, costs and benefits and potential conflicts in the use of DSR by various parties, we have modelled DSR at both the national level (wholesale market and transmission) and the local level (DSO) as seen in Figure 25 below. This chapter quantifies the different uses of demand-side response.

Figure 25 – Overview of our modelling approach



The modelling of national issues uses Pöyry's flagship BID3 wholesale market model while we have used a simple network module to simulate local network issues and therefore determine the local use of DSR.

The first section describes the role of DSR at country level (wholesale markets, ancillary services), and the second section focuses on local distribution grid benefits.

4.1 National issues

4.1.1 Description of the scenario

Estonia is highly integrated with its neighbours, and any analysis of national issues should take into account the interaction between Estonia and its trading counterparts. There are four important groups of countries interacting with Estonia: the hydro-dominated Nordics, the rest of the Baltics, Russia and Continental Europe. The interactions between these four areas and the influence they may have on Estonia are complex, and require a holistic scenario development process.

In 2014, Pöyry carried out a large multiclient study looking at the impact of European decarbonisation policies on the Nordic and Baltic power markets: the Nordics Baltics 2050 study. This study developed consistent paths aiming towards decarbonisation in Europe, following two decarbonisation alternatives as follows:

- *Market Europe* case: based on coordinated and market-led decarbonisation through carbon pricing.
- *National Focus* case: based on uncoordinated government-led decarbonisation through targeted support.

Further details on the scenarios are provided in Figure 26.

Figure 26 – Description of the two decarbonisation pathways in the Nordics Baltics 2050 multi-client study

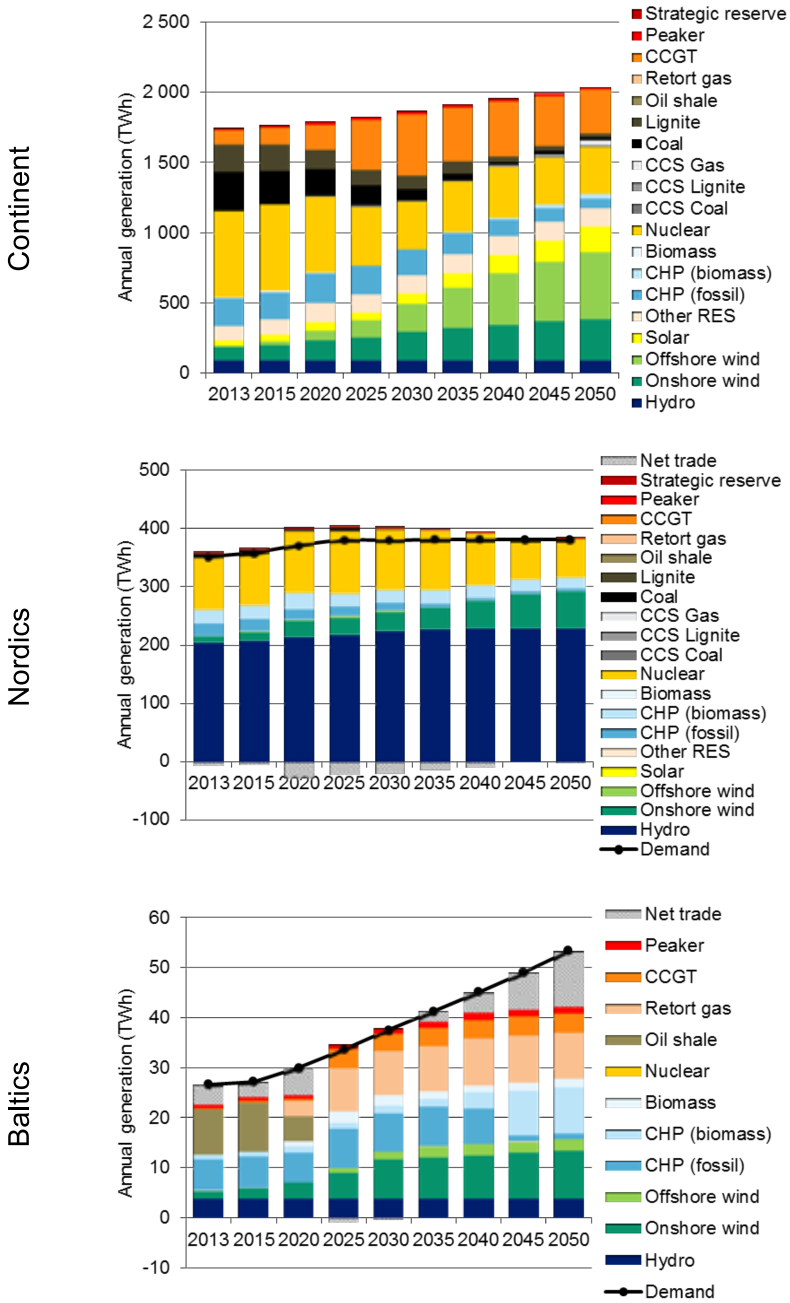
	Coordinated decarbonisation through carbon pricing	Uncoordinated decarbonisatio through targeted support
	Market Europe	*National Focus*
Overall carbon intensity in 2050	50gCO_2/kWh	75gCO_2/kWh
Driver of decarbonisation	Carbon pricing	Targeted support for RES capacity
CO_2 price cap in power sector	High, reaching €120/tCO_2 in 2050	Low, reaching €31/tCO_2 in 2050
Low-carbon, market-based support payment	None	Available, allocated to RES on 'least support' basis to meet targets
Supply/demand adequacy support	Strategic reserve in thermal markets	Capacity payments in thermal markets
Use of interconnection	Energy trading + capacity contribution	Energy trading only
Common features	Scenarios identical up to 2025 (except carbon price), fuel prices, demand development, decommissioning dates	

This study uses the *National Focus* scenario as a basis for the quantitative analysis of DSR. This scenario has more wind capacity than the M*arket Europe* scenario, and therefore is consistent with our intention to reflect optimistic conditions for DSR.

Figure 27 shows the evolution of generation on the Continent, the Nordics and the Baltics in the National Focus scenario. There are several important trends to note:

- On the Continent, 60% of generation comes from renewables by 2050, 15% from Nuclear and 15% from CCGTs. Despite this very significant change of mix, the Continent falls short of the 20gCO2/kWh target.
- In the Nordics, the energy surplus decreases slowly after the 2020s, as low power prices and an already high level of decarbonisation do not incentivise a significant build-out of renewables.
- In the Baltics, the presence of Retort Gas and a sharp increase in demand makes the decarbonisation of the power sector quite challenging.

Figure 27 – Generation (TWh) in the the *National Focus* scenario



Source: Pöyry Management Consulting, Nordics Baltics 2050 study

For this study, the modelling of Estonia has been amended to better follow Elering's view of plausible developments for the demand and supply side; it should be noted that this is one potential development scenario, not Elering's view of likely developments. In particular, a more conservative view on demand growth and retort gas potential to 2030 has been implemented.

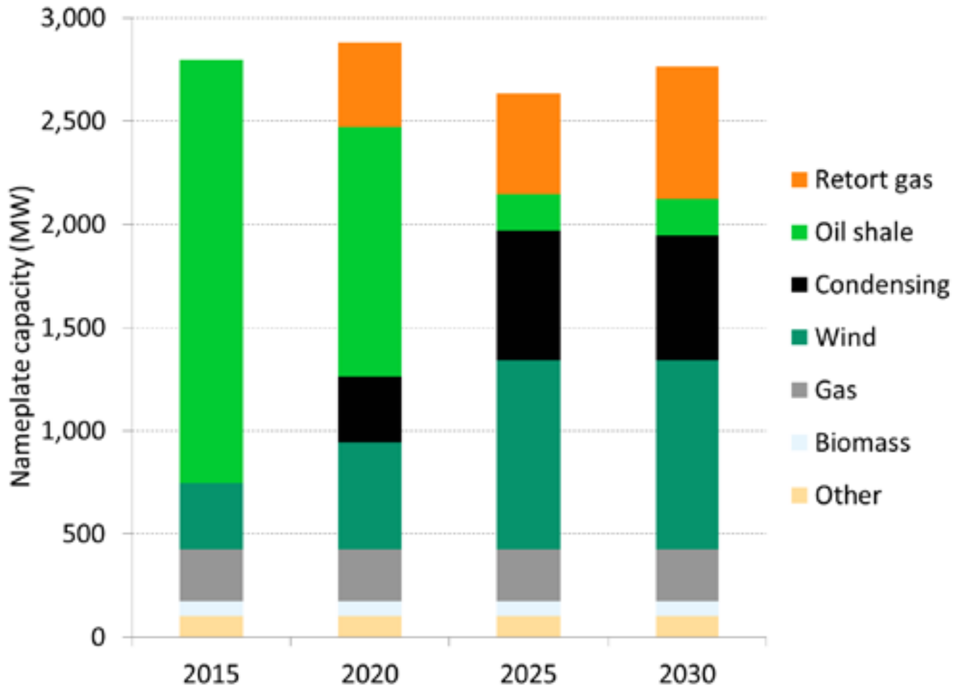
Figure 28 shows the evolution of installed capacity in Estonia. The mix is expected to evolve significantly over the next 15 years:

- Wind capacity triples over the timeframe, to reach 915MW by 2030; and

- Oil shale plants are converted to condensing plants able to burn coal and biomass, and Retort Gas plants appear as a result of the conversion of oil shale into oil products.

The Kiisa power plant appears as 'gas' in Figure 28 , but is kept out of the day-ahead market to provide ancillary services only.

Figure 28 – Installed capacity (MW) in Estonia



Source: Pöyry Management Consulting and Elering

4.1.2 *Modelling tool*

The quantitative analysis at the national level has been performed using Pöyry's proprietary fundamental power market model BID3, used to model the dispatch of all generation on the European network (Eastern Europe and Iberia are represented by fixed flows to the rest of the network). We simulate all 8760 hours per year, generating hourly wholesale prices for each country for each future year and dispatch patterns and revenues for each plant in Europe. Further details can be found in Annex C.

4.1.3 *Use of demand-side response (DSR) for wholesale arbitrage*

There are different types of DSR, including load shifting DSR, and electricity demand destruction. In the first case, DSR displaces demand from a tight period (e.g. peak time) to a looser period (e.g. off-peak time). DSR acts in similar fashion to energy storage, and one of its business models is the arbitrage of hourly differences in wholesale prices. Electricity demand destruction works in a different way: when the wholesale price of electricity is high, some consumers may prefer to decrease their electricity demand, either by switching to an alternative source of energy or by reducing their overall level of demand. This study focuses on the load-shifting DSR, as in our scenario the occurrence of very high price spikes is very limited.

In principle, DSR is used in BID3 in the same way as other elements: the use of DSR is optimal, dispatched in order to minimise system costs. BID3 is therefore representing a perfect use of DSR, and a case where DSR is fully optimised within the wholesale market clearing algorithm of Nordpool.

We have assumed that there is no activation cost for the use of DSR, but that reduced demand must be recovered with a 5% energy penalty. This could represent a 'friction parameter' (a parameter to limit the over-optimisation of DSR in the model) or sometimes a physical energy loss (heating/cooling needs to compensate for hours of lower utilisation). A theoretical example of how DSR could operate in the model is provided in Figure 29.

Figure 29 – Principles for DSR dispatch

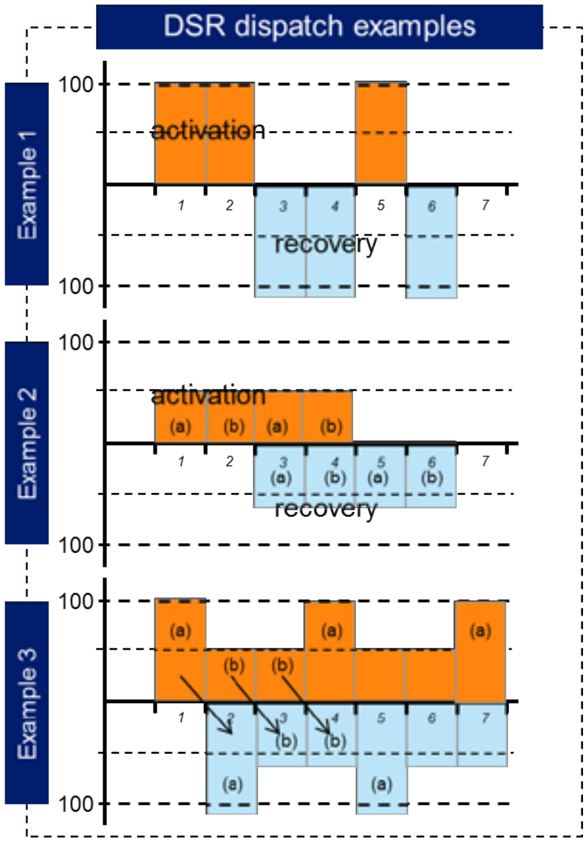
Worked example: Up to 100 MW can be shifted for 2 hours

- a consumer is willing to reduce demand for 2 hours
- reduced demand must be recovered during the next 2 hours
- the same consumer must wait for 2 hours before he's willing to reduce demand again

In example 1, all consumers activate DSR for 2 hours, and then recover demand in the following periods.

In example 2, half of the consumers (group a) activate DSR in hour 1 and recover in hour 3, while the other half (group b) does so an hour later.

In example 3, DSR is constantly activated, by different parts of the consumer group.



For this study we have taken an optimistic view on the potential for DSR in Estonia. The total capacity for DSR is assumed to reach 51 MW in 2020, 129 MW in 2025 and 260 MW by 2030. These assumptions have been guided by Elering, and a detailed breakdown of the assumed potential by sector is given in Table 6.

The DSR potential is split between three categories, depending on the maximum number of consecutive hours that demand may be reduced: Up to 1 hour, up to 2 hours and up to 8 hours. The reduced demand must be recovered within 1, 2 or 8 hours, based on the category, and the same capacity cannot be activated for DSR within this timeframe.

Table 6 – DSR capacity assumptions

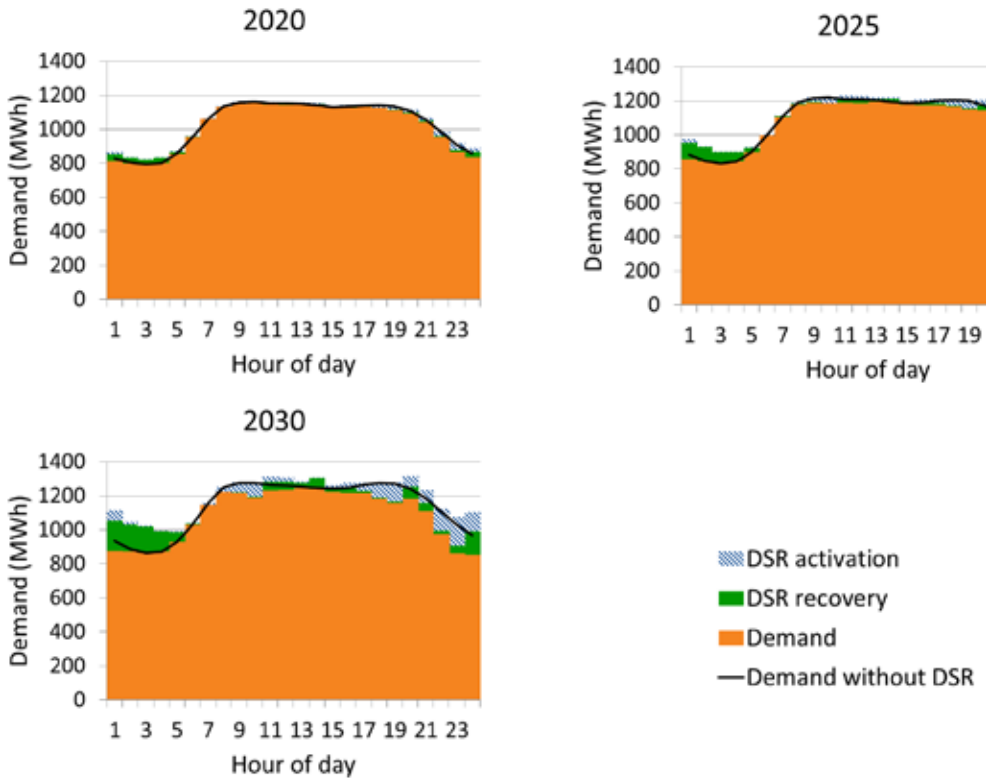
1 hour shiftability (MW)	**2020**	**2025**	**2030**
Water heaters	6.7	16.7	33.5
Electrical heating	2.9	7.2	14.5
Heat pumps	2.5	6.2	12.5
Total	**12**	**30**	**60**
1–2 hours shiftability (MW)	**2020**	**2025**	**2030**
Industry	6.5	16.2	32.5
Office buildings	8.6	21.5	43.0
Wholesale and service sector	2.6	6.5	13.0
Residential	12.1	30.2	60.5
Total	**29**	**74**	**149**
1–8 hours shiftability (MW)	**2020**	**2025**	**2030**
Industry	2.1	5.4	10.8
Office buildings	2.7	6.7	13.5
Residential	5.5	13.7	27.5
Total	**10**	**25**	**51**
Grand total	**51**	**129**	**260**

Source: Tallinn University of Technology

For this study, we have modelled the development of DSR in Estonia only, in order to not obscure DSR benefits in Estonia. In practice, it is more likely that DSR would develop in other countries as well: the results of this study should be interpreted as an incremental development in Estonia compared to a baseline, which for this study is assumed with no DSR anywhere in Europe. This assumption is consistent with the study representing an optimistic view of the benefits of DSR.

Figure 30 shows how DSR is utilised on average during the day. The figure illustrates original demand without DSR (black line), reduction in demand due to DSR (hashed bar) as well as the recovery of reduced demand (green bar). The effect is most significant in 2030 when the potential is largest. As expected, DSR is used to reduce the peak demand around 8–10 and 17–19. In addition, demand is reduced during evening hours and shifted overnight to avoid shutting down power plants when demand normally is lowest. DSR is used to smooth the demand curve to avoid the tightest situations and to decrease the need to switch off and start-up plants.

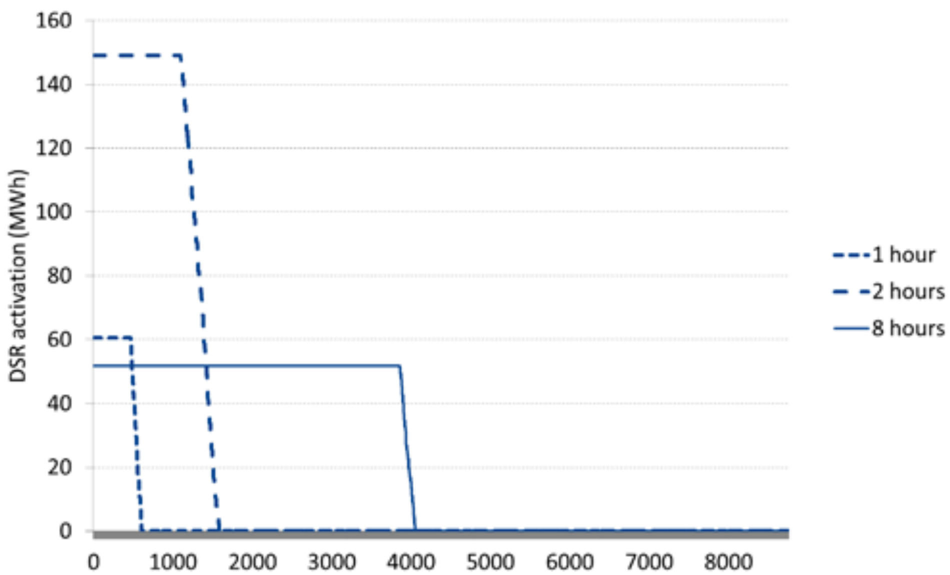
Figure 30 – Average daily use of DSR



Source: Pöyry Management Consulting

The duration curves for the activation of the three DSR categories in 2030 are shown in Figure 31. The 8 hours group, which is the most flexible, is fully activated for nearly 45% of the year.

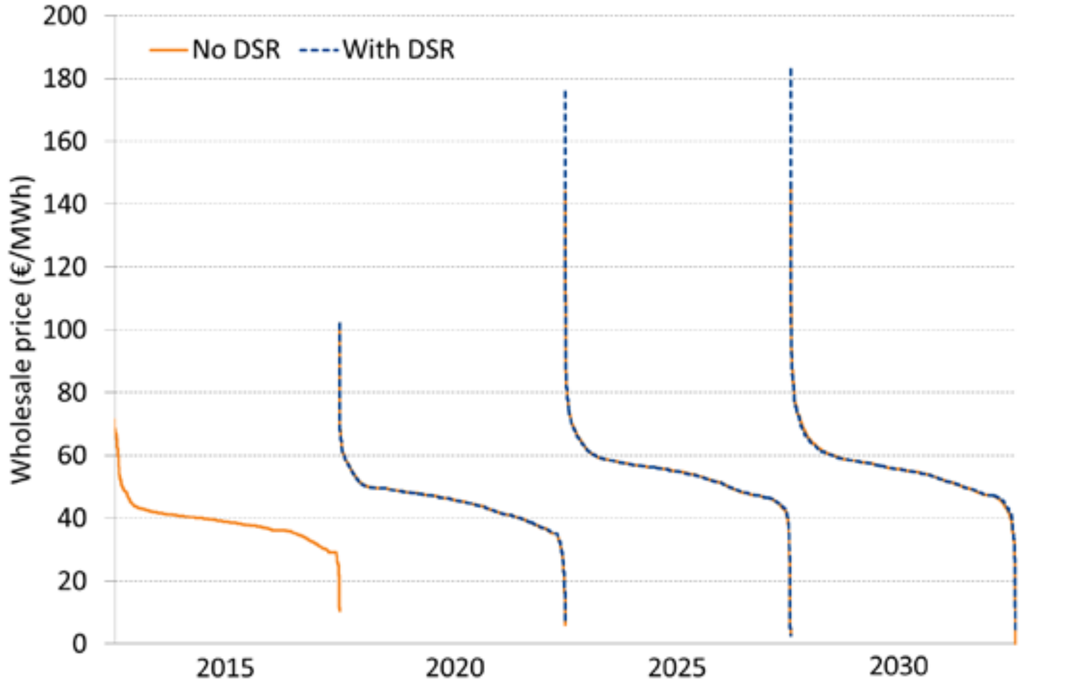
Figure 31 – Duration curves for the activation of DSR in 2030 (MWh)



Source: Pöyry Management Consulting

Figure 32 shows the price duration curves for Estonia with and without DSR: this is the hourly wholesale prices during a year sorted from the highest to the lowest. In 2025 and 2030 DSR can reduce some relatively high price peaks in a few hours, but the overall effect on average prices is very small: the price duration curves are fully superimposed. In 2030 the difference in annual average prices is €0.5/MWh.

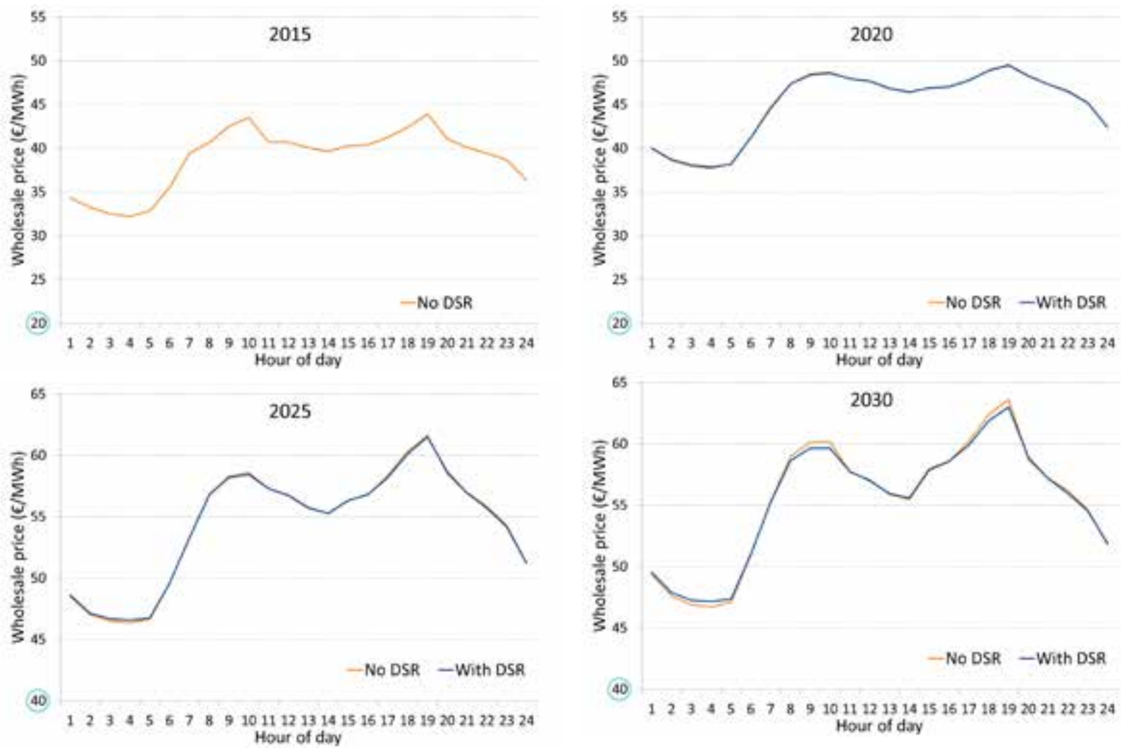
Figure 32 – Duration curve for wholesale prices in Estonia (€/MWh, real 2013 money)



Source: Pöyry Management Consulting

The average daily prices are shown in Figure 33, exhibiting a reduction in prices by €0.5/MWh during the hours 9–10 and 18–19. However, the reduction is offset to increased prices in other hours, particularly at 01–04 where the increase is about €0.3/MWh.

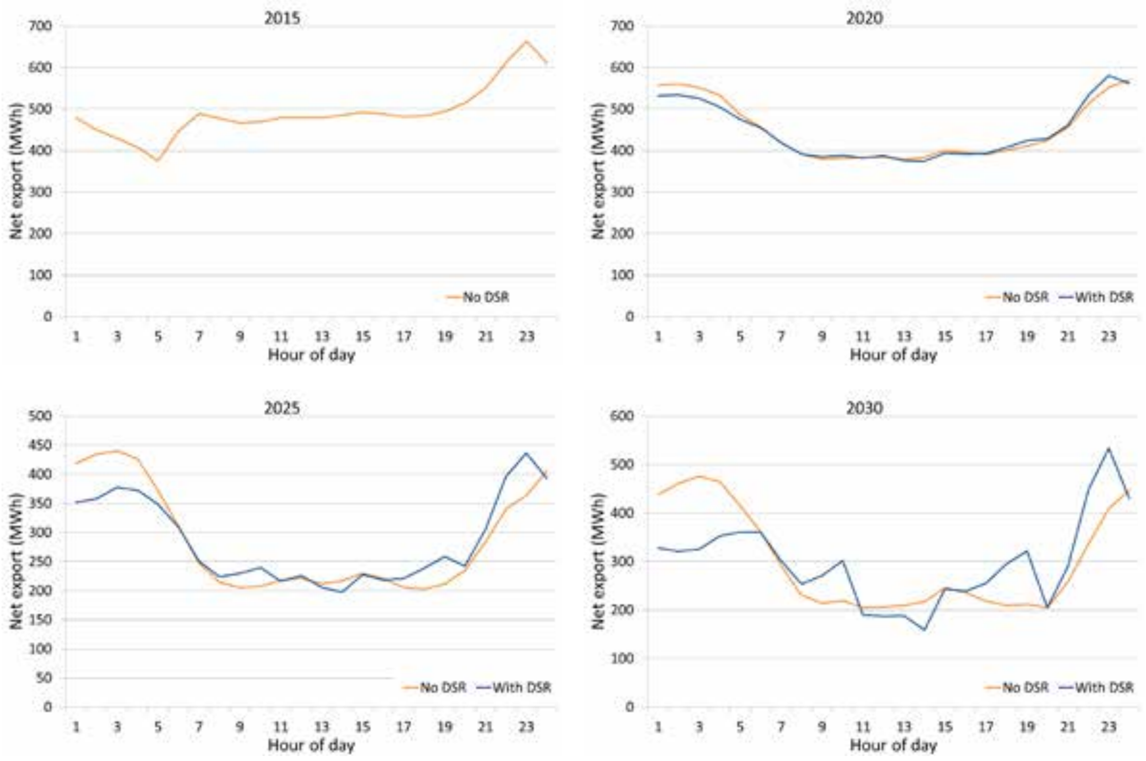
Figure 33 – Daily average wholesale prices (€/MWh, real 2013 money)



Source: Pöyry Management Consulting. Note that the scale starts at €20/MWh then €40/MWh.

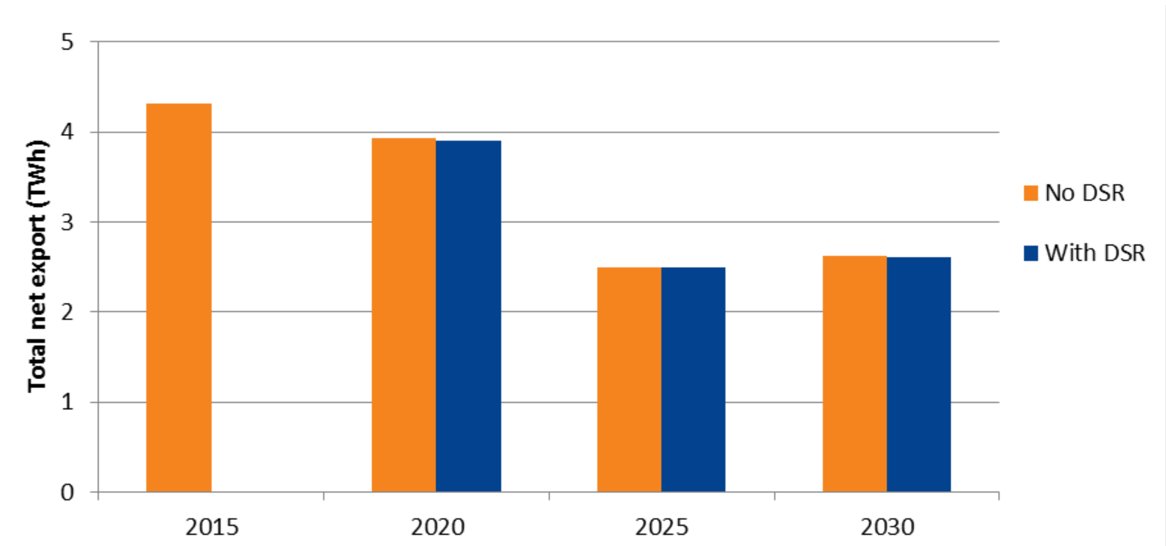
The limited impact on the average daily price shape can be explained by the Estonia's high level of interconnection capacity to neighbouring countries. The model will seek to minimise total system costs, regardless of country borders and therefore Finnish, Swedish and Latvian peak demand is important for the operation of DSR in Estonia. The flexibility introduced in Estonia would be utilised to make plants run more efficiently, and optimise interconnector flows. Figure 34 shows the daily average net export from Estonia. The graphs show that the reduced demand in Estonia during peak hours is offset by increased export. Similarly, as demand is recovered during night hours, the export drops during these periods. The daily pattern for export is highly affected by DSR, but the total annual net export remains similar, as can be seen in Figure 35.

Figure 34 – Daily average net export from Estonia (MWh)



Source: Pöyry Management Consulting

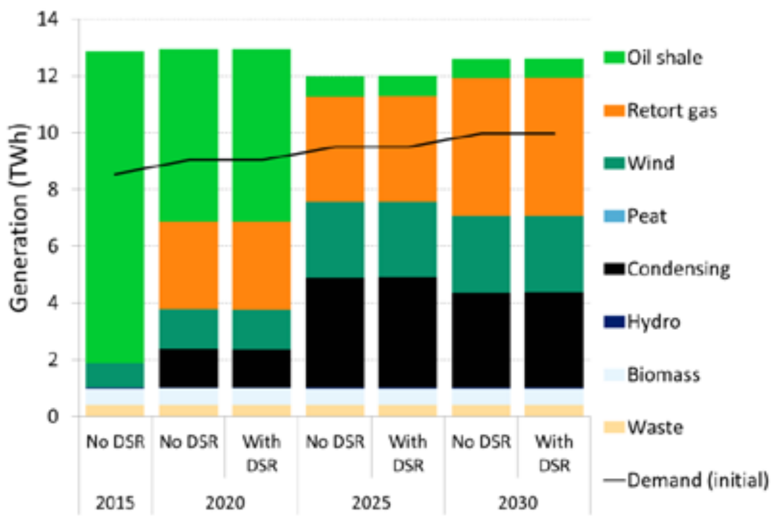
Figure 35 – Net export from Estonia (TWh)



Source: Pöyry Management Consulting

As demand and export is only shifted by DSR but with no change to the total values, total generation in Estonia is constant. Figure 36 shows generation by the various technologies, which produce at the same level in the two scenarios.

Figure 36 – Total generation (TWh)

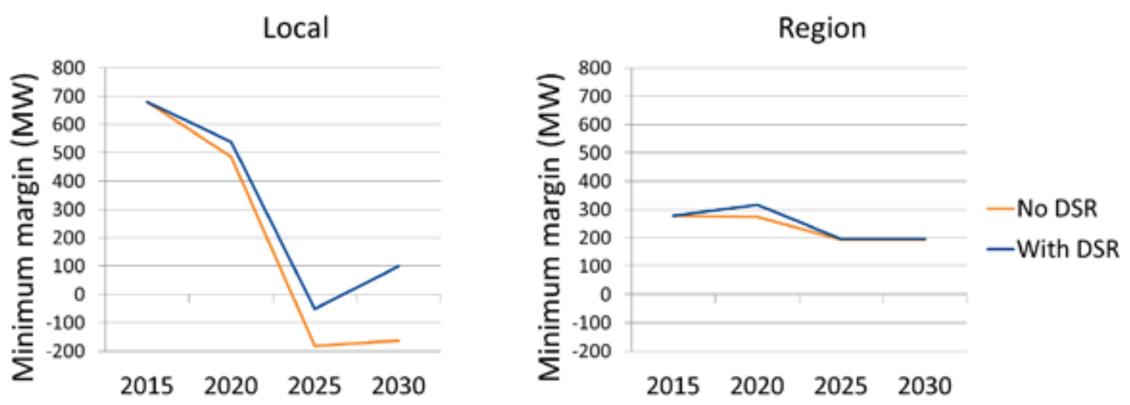


Source: Pöyry Management Consulting

Security of Supply has been evaluated through the metric of the lowest level of spare capacity during the year. This measure can be made at a national level, but this has little meaning in an integrated and liberalised market where a regional approach is more relevant. At the regional level, the security of supply measure represents a world of perfect cooperation between market players and TSOs of different countries, in order to maximise overall Security of Supply. The regional measure still represent Estonia's situation, when including regional interactions.

Figure 37 shows that the local minimum margin can be greatly improved by DSR and helps ensuring Estonia's independence. At a regional level, the margin stays positive overall and DSR does not have a significant effect on the system. In this case, the benefits of DSR on Security of Supply are shared with other regions.

Figure 37 – Security of supply measures



Source: Pöyry Management Consulting

DSR could potentially benefit from a national or regional capacity remuneration mechanism if such a scheme was developed, as DSR in the wholesale market does improve Security of Supply. This potential benefit could only be realised if DSR is available at times of peak demand, and responding to price signals: if DSR is held for reserve for example, its capacity contribution is less clear.

Capacity mechanisms are often designed with requirements on reliability and characteristics of capacity provision. In general, DSR must be explicitly and separately considered in designing a capacity mechanism, as otherwise some requirements given to power plants may rule out most of the DSR potential: this could be for example the requirement for plants/DSR to respond to capacity margin tension for 8 hours in a row.

4.1.4 Use of DSR for wholesale and reserve holding arbitrage

For this study we have also used BID3 to model the holding of reserve. This is done by co-optimising the reserve holding and the day-ahead market, i.e. the model seeks the cheapest way of meeting demand without violating the reserve holding constraints. The model will, for each hour, determine whether a plant eligible for reserve holding should reserve some of its capacity or if it should be fully available for the day-ahead market. Note that in today's market design, this is generally done on a weekly, rather than hourly, basis for peak and off-peak periods.

In order to hold reserve, a plant must be able to change its output very quickly up or down. For up-reserve, a thermal plant will have to generate below its maximum capacity. For down-reserve, a thermal plant must generate above its minimum stable generation. It is assumed that only plants that are synchronized can contribute to primary and secondary reserve, whereas any plant not running can be used for tertiary reserve. Note that the latter is different from other markets like Germany for instance. The reserve plant Kiisa can contribute to secondary and tertiary reserve, even when not synchronised. Plants assumed ability to hold reserve is provided in Table 7.

Table 7 – Share of plants available capacity that can be used for reserve holding

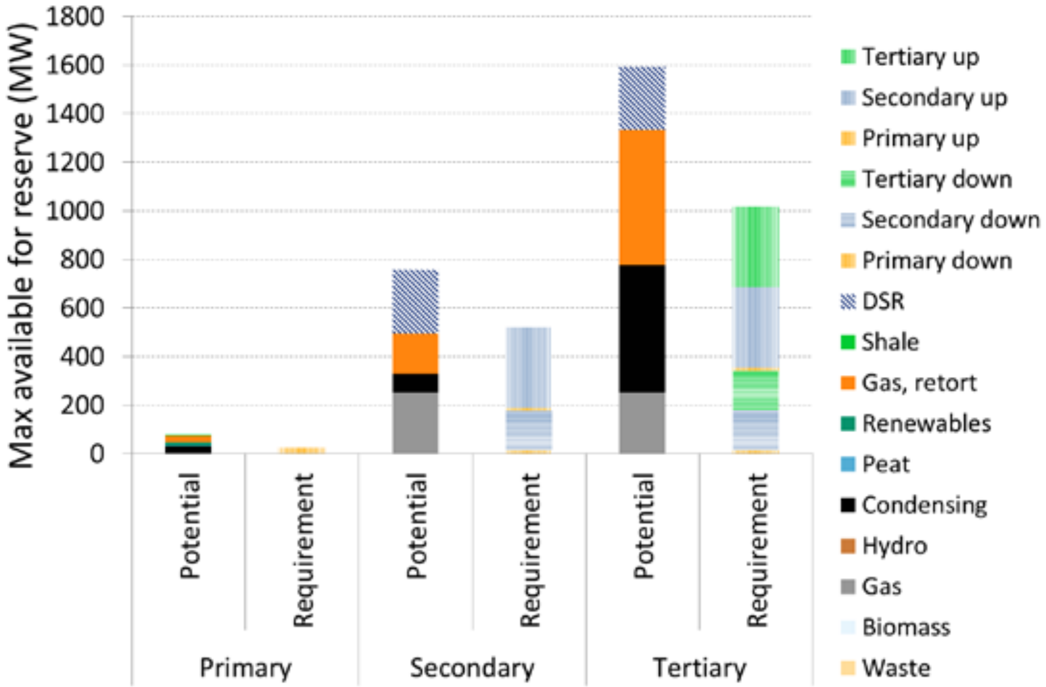
Share of available capacity	Primary	Secondary	Tertiary
CCGT	5%	20%	100%
Coal	5%	15%	100%
Oil shale	5%	30%	100%
Wind	5%	-	-
Kiisa	-	100%	100%
DSR (only up-reserve)	-	100%	100%

Source: Pöyry Management Consulting

The requirements for up- and down-reserve in Estonia are assumed to be symmetrical at 13 MW, 330 MW and 330 MW for primary, secondary and tertiary reserve, respectively. In our study, DSR can be fully used to hold secondary and tertiary reserve. For the down-requirements however, we have assumed that parts of this can be met by specific agreements increasing end-users consumption, or shared with other countries. In the model the requirements for secondary and tertiary reserve are therefore reduced to 165 MW and DSR is not allowed to be used for holding down-reserve.

Provided that the reserve holding requirements must be met by Estonian capacity alone and a megawatt capacity can only hold one type of reserve at the same time, the potential for reserve holding capacity in Estonia is sufficient, but tight. In Figure 38, the requirement for primary and secondary is stacked together with the tertiary requirement as all of them must the met at the same time. Note that 165MW is shown for the secondary and tertiary down-reserve requirement, not 330MW.

Figure 38 – Potential for reserve holding capacity in Estonia (MW)

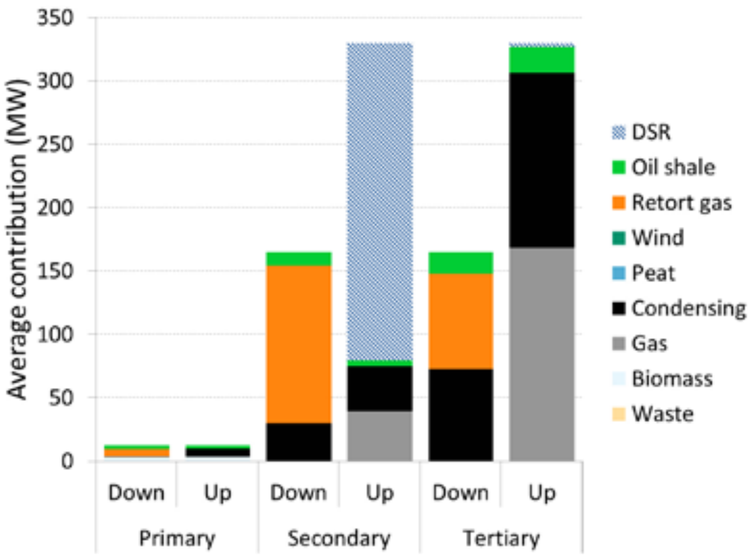


Source: Pöyry Management Consulting

Introducing reserve holding requirements has a significant impact on the Estonian power market. Plants may be forced to produce above minimum stable generation in order to hold down-reserve. Similarly, plants that normally would operate at a higher load factor may be forced to reduce production in order to hold up-reserve. The plants characteristics and ability to hold reserve may disturb the traditional merit order for the day-ahead market.

The average holding of reserve by plant type is shown in Figure 39. The reserve plant Kiisa appears in the Gas category and contributes largely to tertiary and secondary reserve, 208 MW on average. DSR is heavily used to hold up-reserve, 253 out of 260 MW on average. While thermal plants must be spinning in order to hold secondary reserve, DSR is relatively flexible and is therefore used for this purpose. In the modelling, there is no difference in the characteristics between DSR and Kiisa when it comes to reserve holding, so the split between those two in the holding of secondary versus tertiary reserve is somewhat arbitrary.

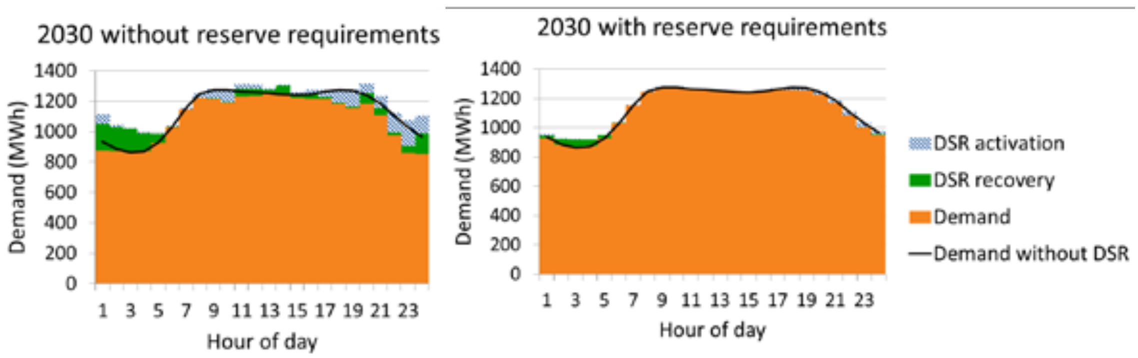
Figure 39 – Average reserve holding (MW)



Source: Pöyry Management Consulting

As DSR is used for reserve holding, the potential for shifting demand is significantly reduced. Figure 40 shows DSR activation in 2030 with and without the requirements for reserve holding. Demand is still reduced in order to be recovered during periods with low demand, but the magnitude is much lower than without the reserve holding.

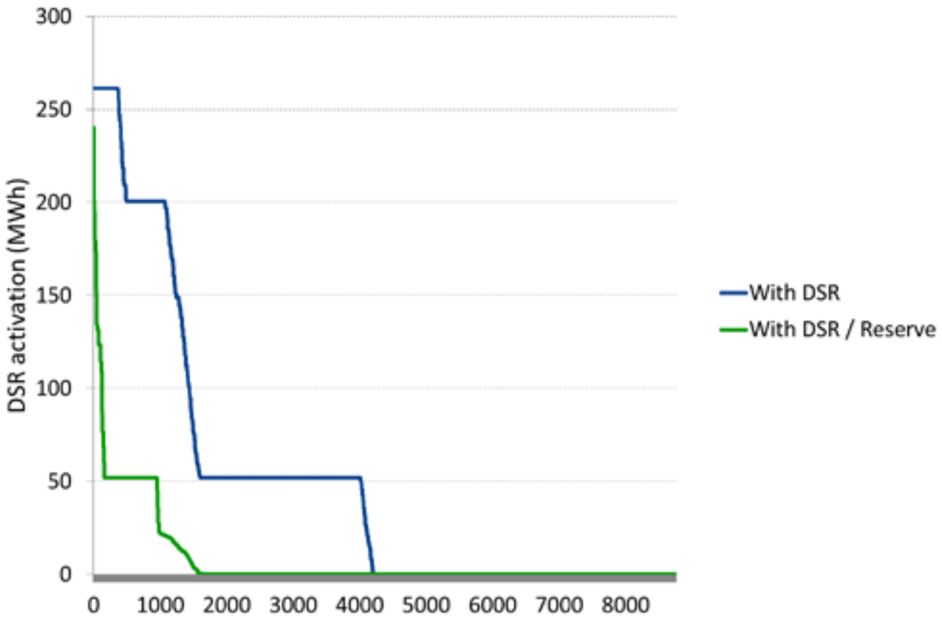
Figure 40 – User of DSR in 2030 with and without reserve holding requirements



Source: Pöyry Management Consulting

Figure 41 shows the duration curves for the activation of DSR in 2030 with and without the reserve constraints. When the reserve holding is introduced, DSR is (partially) activated for demand shifting in only 19% of the hours. Without the reserve constraints, DSR is used for circa 45% of the time.

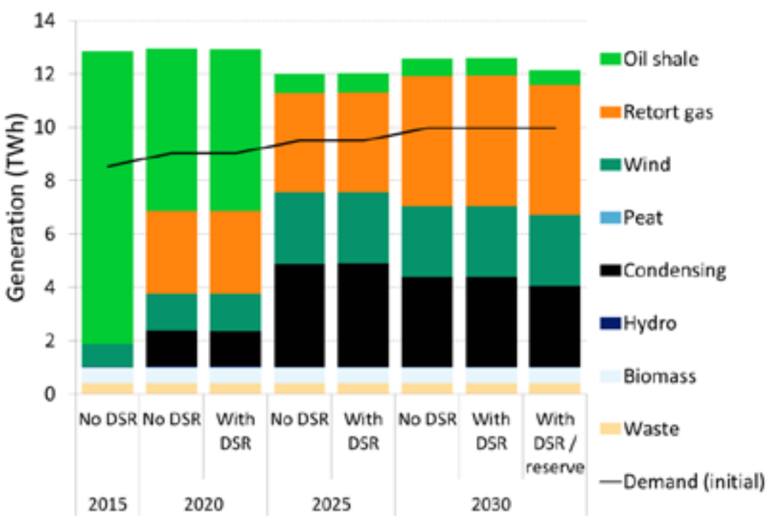
Figure 41 – Duration curves for the activation of DSR in 2030 (MWh)



Source: Pöyry Management Consulting

The holding of reserve not only affects DSR but also the dispatch from producing plants. As shown in Figure 39 retort gas is holding the majority of down-reserve while oil shale and condensing plants are reserved for up-regulations. Figure 42 shows the annual generation from the different plants in Estonia. The introduction of reserve requirements limits the generation from oil shale and condensing plants by 0.13 TWh and 0.34 TWh, respectively.

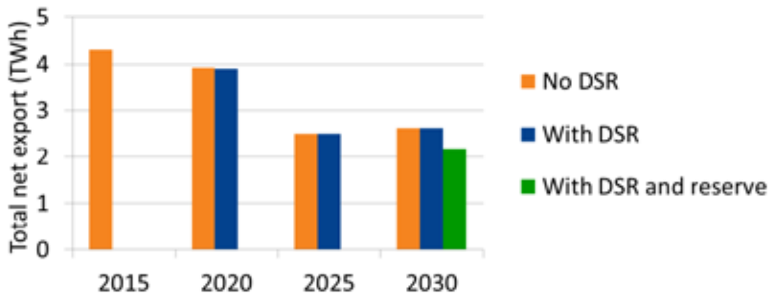
Figure 42 – Annual generation in Estonia (TWh)



Source: Pöyry Management Consulting

The change in annual generation is reflected in the net export from Estonia. As shown in Figure 43, export decreases by 0.44 TWh in 2030 when reserve constraints are activated. Rather than producing for export, plants are required to hold up-reserve.

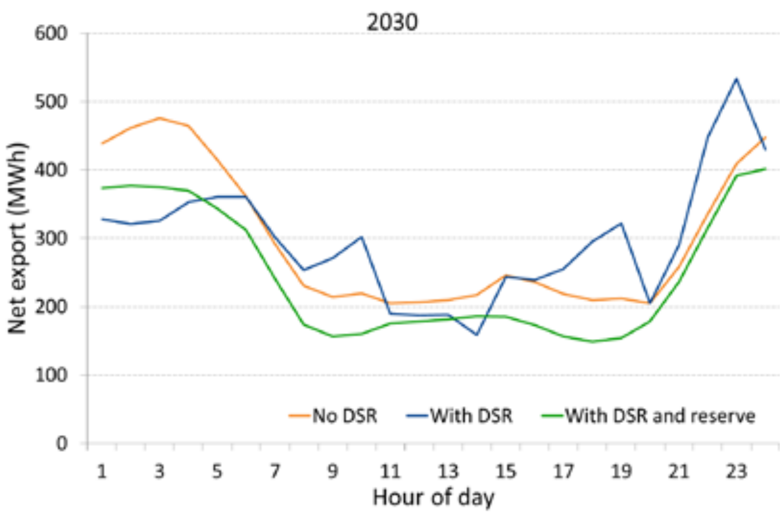
Figure 43 – Total net export from Estonia (TWh)



Source: Pöyry Management Consulting

This effect can also be seen in the daily average net export, see Figure 44. The level of export is lower than the two other scenarios; however, the shape of the curve is similar to the scenario without DSR, as DSR is reserved for the up-requirements.

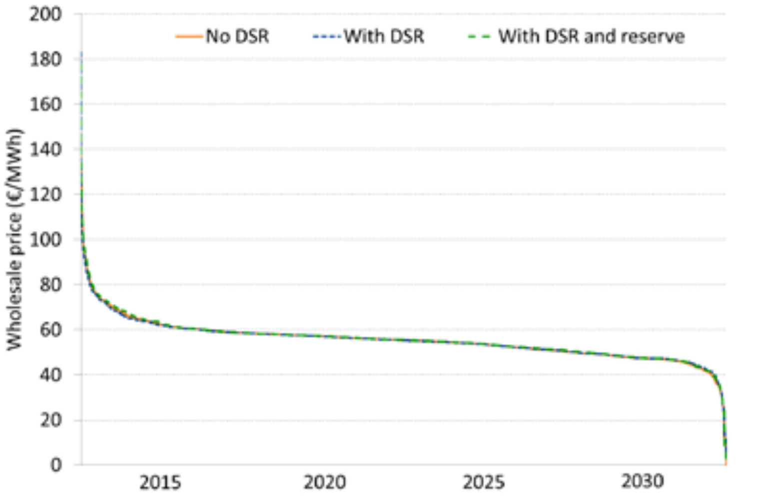
Figure 44 – Daily average net export from Estonia (MWh)



Source: Pöyry Management Consulting

As expected, wholesale prices are increasing with reserve holding constraints, as part of the capacity cannot be used for the wholesale market. The average price increases by €0.34/MWh compared to the scenario with DSR and €0.29/MWh compared to the scenario without DSR (but also without reserve holding). Figure 45 plots the duration curves for the three scenarios, which shows that reserve requirements do not significantly change the shape of prices overall.

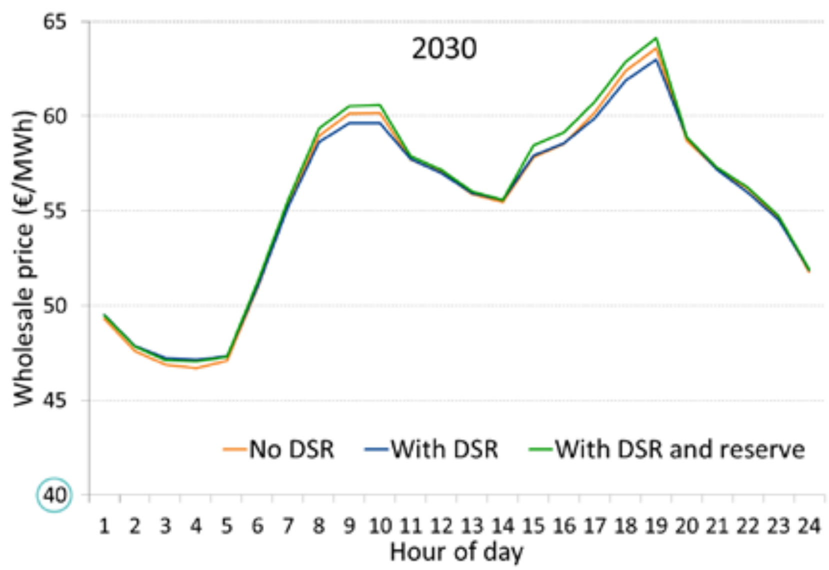
Figure 45 – Duration curves for Estonian wholesale prices (€/MWh, real 2013 money)



Source: Pöyry Management Consulting

With less capacity available for the wholesale market and no use of DSR, the peak hours would become slightly tighter. This can be observed in Figure 46.

Figure 46 – Daily average wholesale price in Estonia (€/MWh, real 2013 money)



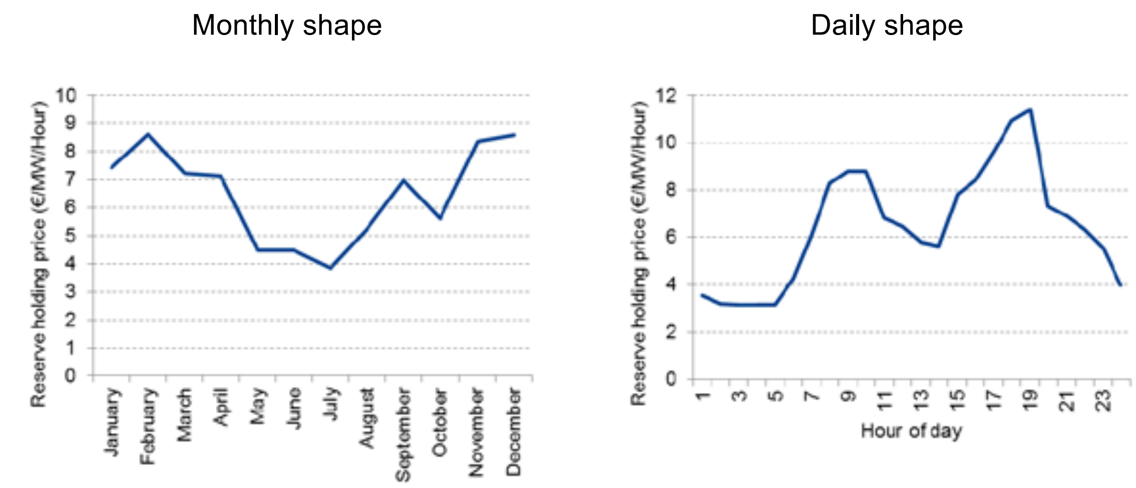
Source: Pöyry Management Consulting

The reserve holding prices are a direct result of our modelling, and are shown in Figure 47 at the monthly and within-day resolution. The average price of holding up reserve is ~6€/MW/hour.

Revenues for DSR from holding reserve in €/MW/hr can be seen as a capacity price for the reserve market. The value reflects the additional cost of holding capacity to provide reserve. This holding price is dynamic and depends on system conditions e.g. the availability of thermal plant to provide reserve during peak compared to off peak hours. If the plant holding reserve would be activated, an activation price would be applicable (to reflect e.g. the cost of dispatch). From the owners perspective, in general, revenues from activation are far smaller than those for holding reserve.

Unsurprisingly, up-reserve is more valuable in winter times, and during day-time. It is worth pointing out that BID3 produces hourly marginal reserve prices, but that today's procurement rules are generally different. In some markets like Germany, the procuring is done by weekly auctions for peak and off-peak products.

Figure 47 – Up-reserve holding prices (average €/MW/hour, real 2013 money)



Source: Pöyry Management Consulting

4.1.5 *Intraday and balancing markets*

The Intraday and balancing markets are responsible for addressing potential forecasting errors for wind and demand, as well as unplanned outages. In theory, DSR has the potential to react to these events and balance the system by complementing the day-ahead market.

The balancing market size was €3.8m in 2014 with an average price of €65.01/MWh for up-regulation and €24.24/MWh for down-regulation[27]. The volumes in the balancing market were 34 GWh up-regulation and 65 GWh down-regulation in 2014. The size of the intra-day market, Elbas, was €5.2m in Estonia in 2014 with an average buy price of €47.04/MWh[28]. The volume purchased from the Elbas market in Estonia was 111 GWh in 2014. For comparison, the average price in the day-ahead market, Elspot, in Estonia was €37.61/MWh in Estonia.

Currently, we observe higher price volatility in the balancing market than in the day-ahead market, which could suggest that DSR could make significant revenue in this market. Between 1 January and 10 June 2015, the average premium for imbalance buy price was €5.5/MWh, and up to €50/MWh for some hours[29].

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[27] Source: Elering

[28] Source: Nord Pool Spot

[29] Source: Nord Pool Spot and Elering websites

However, there are several trends which could flatten these prices and reduce opportunities in the future for DSR:

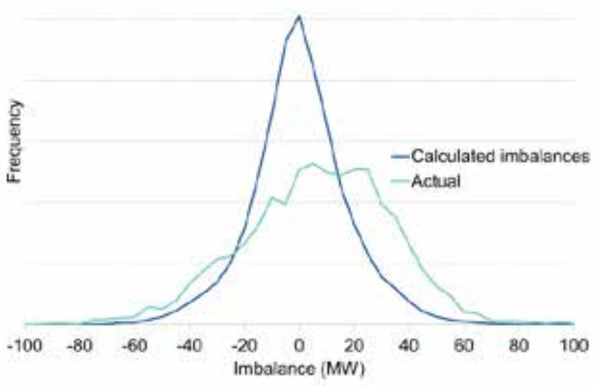
- Traded volumes are typically relatively low on the balancing market, and were on average 25MW for the first five months of 2015, which limits the 'depth' of the market.
- Wind forecasting is constantly improving, limiting the need for balancing.
- The regional integration of balancing markets with neighbouring regions is likely to decrease the price volatility in this market given the importance of hydro in the Nordics.

Given this significant uncertainty on the price side, we have approached the assessment of the potential for the use of DSR after the day-ahead stage by looking at the evolution of forecasting error. The investigation of forecasting error evolution has been focused on wind and demand. The other sources of imbalances (unplanned outages, etc.) are not included as part of this analysis.

The calculation of imbalances in this study is derived from statistical analysis of forecasting errors in Germany. The calculations are made at 15-minute intervals, and imbalances are the results of stochastic parameters and typical error factors observed in the market.

Figure 48 shows the distribution of imbalances from Pöyry's calculations compared to actual reported imbalances from 1 January to 10 June 2015. There are differences between the two curves, and in particular the actual imbalances are positively skewed. As the events of unplanned outages are not captured as part of Pöyry's calculations, the analysis performed for this section should be seen as a semi-quantitative benchmark rather than an actual prediction of imbalances.

Figure 48 – Benchmark of imbalance distribution

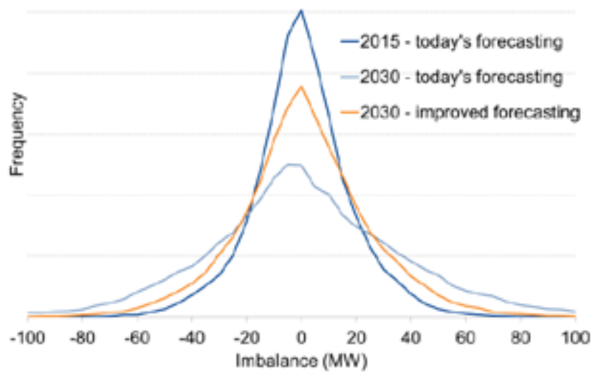


Source: Pöyry Management Consulting and Elering website

There are two factors which mechanically increase the range of imbalances in Estonia over time: the increase in demand, and the increase in wind capacity. This can be seen on Figure 49 when comparing the curves '2015-today's forecasting' and '2030-today's forecasting': in 2030, the distribution of absolute imbalance is fatter.

We have included another element of evolution over time: the expected improvements in wind forecasting. There is a considerable uncertainty in this field, and also on the resulting distribution of forecasting errors for our modelling purpose, but there is a clear trend which we have observed in Great Britain and Germany. According to Pöyry's analysis of wind forecasting errors, the day-ahead error decreased from 7.5% in 2012 to 5.3% in 2014 in GB, and from 4.5% in 2010 to 3.2% in 2014 in Germany. The differences between GB and Germany can be attributed to a number of factors including geographical spreads and weather patterns. Figure 49 shows that when including an improvement in wind forecastability (curve '2030 – improved forecasting'), the distribution of absolute imbalances may come much closer to today's curve.

Figure 49 – Distribution of imbalances



Source: Pöyry Management Consulting

This analysis is a high-level evaluation of the need or potential for DSR to balance wind. The calculations suggest that there is an increase in balancing needs in Estonia, but that the potential for DSR on the balancing market is limited, given that:

- Today's market can cope with imbalances.
- There are factors which may dampen price volatility in the within-day market.
- The evolution of wind and demand is not expected to increase significantly the level of imbalances, as wind forecasting improvements may partly compensate for the increase in wind capacity.

4.1.6 Benefits of DSR at the national level

The quantitative analysis performed so far indicates that load-shifting DSR would change patterns of prices, generation and exports in Estonia. This section will investigate whether there are quantifiable benefits of DSR in Estonia, and how much revenues could be generated from DSR by aggregators.

Cost to consumers

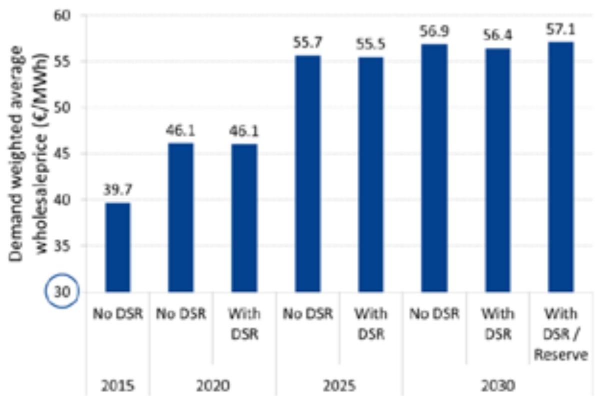
The impact on the cost to consumers has been evaluated by the variation of the cost of electricity for consumers in Estonia: this is the electricity price multiplied by demand, for each hour.

Figure 50 shows the demand weighted average wholesale price in Estonia (€/MWh), as well as the variation of electricity cost to consumers compared with the case without DSR. DSR decreases wholesale prices slightly during periods of high consumption, and increases wholesale prices slightly during periods of low consumption: this means that overall consumers will pay less for their electricity. The benefit of DSR on the cost for consumers is up to €3m in 2030, corresponding in a change of €0.5/MWh on the demand-weighted price.

The demand-weighted price of electricity increases with the introduction of reserve constraints, by €0.7/MWh, or €5.3m (from +3 to -2.3 €m difference to case without DSR) compared to the case with DSR.

Figure 50 – Impact of DSR on cost to consumers, real 2013 money

Demand-weighted electricity price



Variation of electricity cost to consumers compared to case with no DSR (€m)

2020-wholesale only	0.5
2025-wholesale only	1.0
2030-wholesale only	3.0
2030-wholesale and reserve	-2.3

Source: Pöyry Management Consulting

Avoided investments

Our analysis suggests that the power plant park of 2030 without DSR cannot meet the reserve requirements imposed in this study. In this case, DSR offsets building a new power plant of the same type of the Kiisa power plant, which had reported costs of €137m for 250MW of capacity[30].

The exact dimensioning of the investment which would be displaced by DSR is rather uncertain: our modelling suggests that an additional unit of 125MW would be sufficient to meet the reserve requirements together with the rest of the park. The investment displaced could therefore be approximated to half the cost of building the Kiisa two 125MW units, i.e. €68m.

Business case for aggregators

We have investigated the potential business case for aggregators who would be controlling DSR for the benefit of consumers.

On the wholesale market, aggregators would get commercial revenue directly from the wholesale market by replacing high-priced consumption with lower-priced consumption.

On the reserve side, aggregators would get revenues from committing DSR to reserve holding and getting a ‘reserve-holding’ capacity price, as well as getting revenues from ‘reserve-activation’. This study has focused on ‘reserve-holding’ revenues and does not assess activation revenues which in our experience are more limited.

Both sources of revenues for 2030 are presented in Figure 51. Revenues from DSR for aggregators are significantly higher in the reserve market than in the wholesale market.

30 Source: €135m in 2012 money http://www.baltic-course.com/eng/energy/?doc=58713

Figure 51 – Revenues for aggregators of DSR

Million euros, real 2013 money	DSR for wholesale arbitrage only	DSR for wholesale and reserve arbitrage
Wholesale arbitrage	2.1	1.7
Reserve holding	-	14.4
Total	2.1	16.0

Source: Pöyry Management Consulting

4.1.7 Summary of benefits

Figure 52 summarises all the benefits presented in the previous sections, at the national level.

Figure 52 – Summary of benefits for DSR (real 2013 money)

	DSR for wholesale arbitrage only	DSR for wholesale and reserve arbitrage
Benefit for consumers	€3m	N/A
Avoided investment	0	€68m
Security of Supply	+	+
Balancing	≈+	≈+
Business case for an aggregator	€2.1m	€16.0m

Source: Pöyry Management Consulting

4.2 Local issues

DSOs have the potential to utilise DSR to alleviate constraints on local networks. There are a number of sub-cases where this may be useful, such as:

1. Absorbing excess local generation (e.g. wind) where there is insufficient network capacity to support it.
2. Deferring reinforcement of a congested network where the capacities of substations or circuits are being exceeded.
3. Deferring reinforcement of a congested network to maintain N-1 security.
4. Delaying reinforcement where demand forecasts leave uncertainty as to whether investment in firm capacity will be required.
5. Installing lower-capacity infrastructure when replacing assets at the end of their economic life.

Our modelling of DSR use at the local level uses a simple network module to simulate DSR dispatch on a network where the substation is constrained (e.g. cases 2 to 5, where the constraint is on a substation). The network module focuses on four representative node types (urban core, urban, suburban and rural), representing the types of network found across Estonia.

4.2.1 Modelling methodology and assumptions

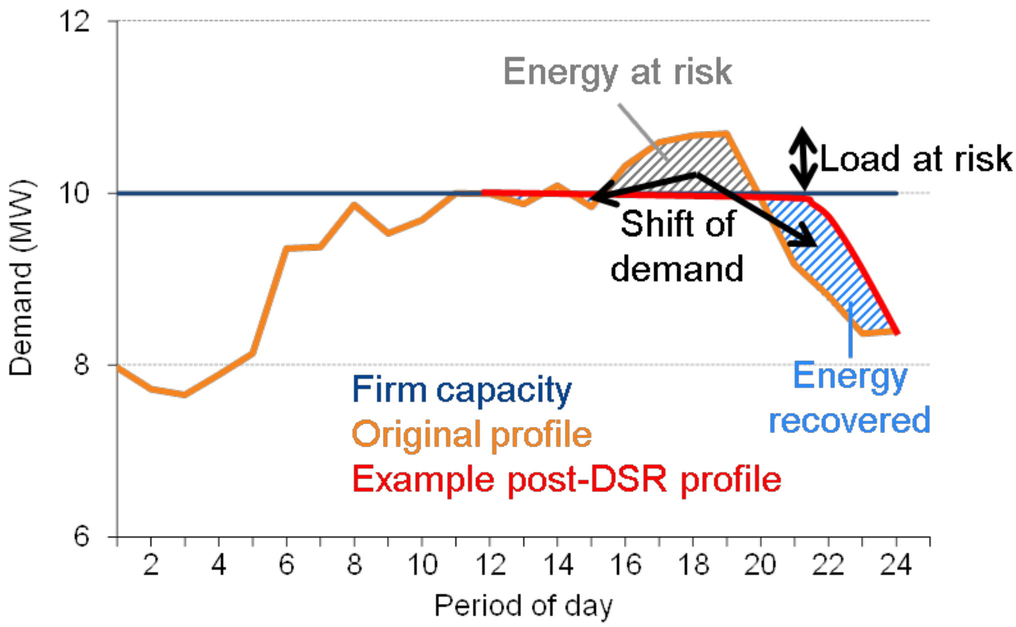
The module contracts DSR to meet peak demand based on historical weather patterns (2009-2013), and possible future stress levels on the network, and dispatches DSR to reduce demand to firm capacity when needed.

To model the representative network nodes, we used historical hourly load profiles provided to us by a DSO for two 10kV substations corresponding to the rural and suburban characteristic network types. We did not have load data for the other two network types, but assumed in the economic modelling that they would have similar characteristics to the suburban station.

The capacity shortfall at a network node is calculated based on the peak of the demand profile using historical data, and the firm capacity of substations. Lacking specific information about transformer properties, we have made the simplifying assumption that the firm capacity is equal to the rated capacity for transformers. While many transformers may be pushed to higher load levels than this, it does not affect the conclusions of this work, but merely ’shifts the goalposts’ for when DSR need be used.

DSR is dispatched to reduce the load on the node to firm capacity. The principle of this behavior is illustrated conceptually in Figure 53, along with an introduction to terms used later (“load at risk”, “energy at risk” and “energy recovered”)..

Figure 53 – Principle of DSO use of DSR



Source: Pöyry Management Consulting

There are a number of different ways in which DSR can be dispatched within the network module. In this work, we have chosen rules that match the assumptions used in the BID3 modelling of the wholesale and reserve markets, and which are based on our assumptions around how DSR is likely to work. As DSR schemes become more common, more information will become available on how they are used and what restrictions exist on their flexibility. We consider that these rules deliver a good framework, given the present understanding of DSR, for investigating when DSR is likely to be used in the future.

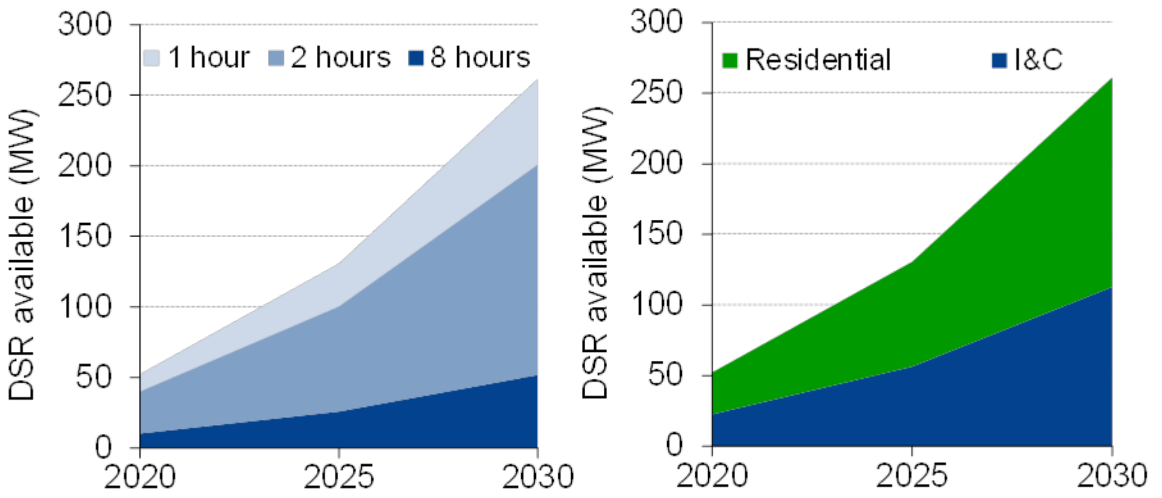
On a single day, DSR dispatch behavior is economically optimised: that is, DSR is dispatched in small aggregated blocks, so that, if possible, load is reduced to firm capacity but not, typically, below it. The model will dispatch DSR to shift demand from periods of stress to periods that have no network with load at risk, subject to the specified technical constraints of the DSR. The DSO is assumed to have good foresight of the demand that will appear on their network during the day, and a framework in place that allows them to access the DSR if required (subject to having paid availability costs to procure the DSR, below).

Three categories of DSR are utilized in the model, all of which shift demand when they are called, to a different period of time. As for the BID3 modelling, it is assumed that the DSO can control when the demand can be shifted to, and that there is a 5% increase in total demand caused by the shifting; that is, using DSR to shift 1.00 MWh of energy at risk will result in 1.05 MWh of energy being recovered at an earlier or later time. The three categories of DSR are:

- DSR with 1 hour of flexibility, which can shift demand earlier or later by one hour, and covers sources such as residential heating. This source can be utilised for at most three hours per day.
- DSR with 2 hours of flexibility, which can shift demand earlier or later by either one or two hours. This covers a range of sources including residential, commercial and industrial DSR. This source can be utilised for at most four hours per day.
- DSR with 8 hours of flexibility, which can shift demand by up to 8 hours, and includes DSR from industrial, residential and building load sources. This source can be utilised for at most six hours per day.

The volume of DSR assumed to be available across Estonia is shown in Figure 54, split by flexibility and source of DSR (I&C or residential).

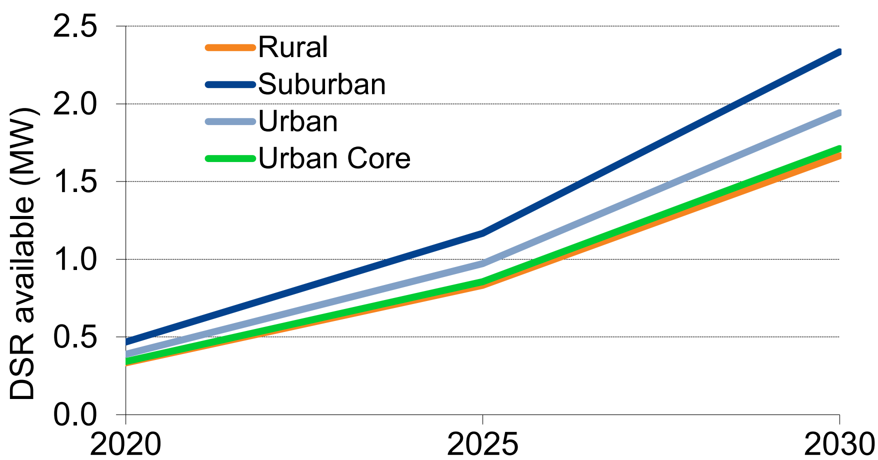
Figure 54 – National DSR availability by flexibility and source



Source: Pöyry Management Consulting

The volume of DSR available on each node type is estimated based on the breakup of DSR between Residential and I&C sources, and assumptions around the level of residential and I/C load on each network. The resultant volumes of DSR available for each network type, assuming 10 MW peak annual load, are shown in Figure 55.

Figure 55 – Local DSR availability



DSR volume shown assumes a 10 MW peak load on the substation. Locations with different load levels are assumed to have a volume of DSR proportional to the load.

Source: Pöyry Management Consulting

The volume of DSR on each network node type is based on the national average, and we assume any individual substation may have access to considerably more or less DSR than these figures. For example, if the DSO was strongly interested in using DSR at a specific location, they may be able to recruit more sources than indicated in the average figures. One example of where this could be the case relates to cases of DSR use highlighted earlier in Figure 17 and Figure 19.

We have used the averages as hard limits when investigating dispatch behaviour in sections 4.2.2 to 4.2.4, but shown them only as indicative references for financial considerations in section 4.2.5, where the financial case assumes that sufficient DSR is available to procure. DSO schemes would likely only go ahead if sufficient DSR could be procured locally.

We have not considered the role of embedded flexible generation (such as backup generation), or DSR that results in demand destruction, for this modelling. In our experience, we have generally found that DSR that destroys demand is more favourable for DSO usage, and may help to avoid some of the issues associated with low-flexibility demand shifting that are discussed in later sections.

Our modelling assumes that DSR is procured to be available by season, defined as:

- November to February, for winter.
- June to August, for summer, if DSR required in summer.
- September to October, if DSR required in autumn.
- March to May, if DSR required in spring.

DSR is procured only to the level required within a season, and paid for its availability at 0-10 €/MW/h, for 8h/d, 5d/wk, for the duration of a season. If necessary to meet weekend loads, DSR may be recruited for 7d/wk, although this is typically not the case. DSR is paid for utilisation (i.e. when called in) at €80/MWh, which represents a high-cost usage fee compared to the BID3 modelling of demand-shifting DSR, although would be low-cost for most forms of demand-shedding DSR.

Reinforcement investments are assumed to be lumpy, such as the addition of a new 4 MVA transformer, and costs are charged at a generic rate of €40,000 per MVA of capacity added. Financial graphs in chapter 4.2.5 also show low and high reinforcement costs of €20,000 and €60,000 per MVA respectively.

4.2.2 Local network usage patterns of DSR

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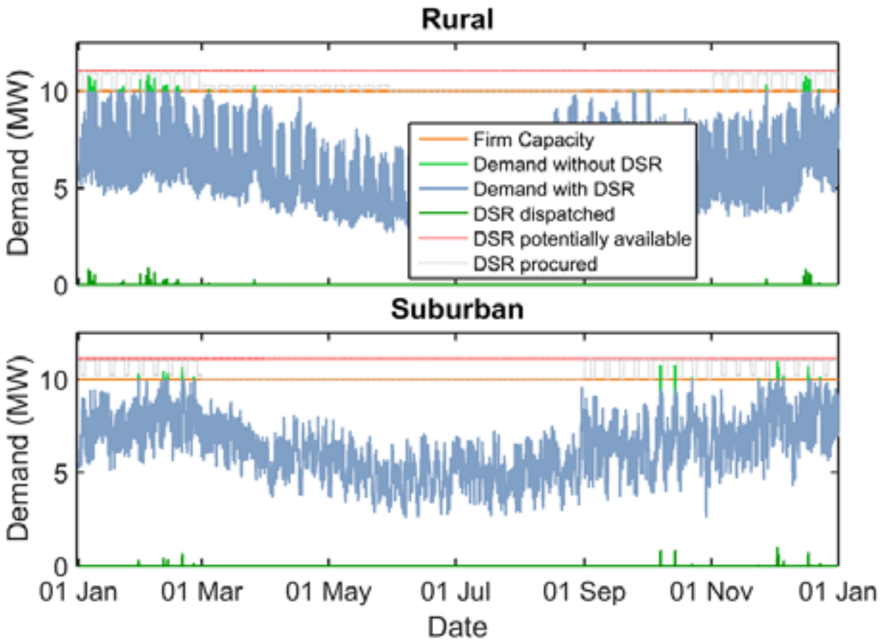
Figure 56 and Figure 57 show the DSR use across two representative nodes in 2025, at annual and daily resolution respectively. The pictures show a number of different features of the network module results:

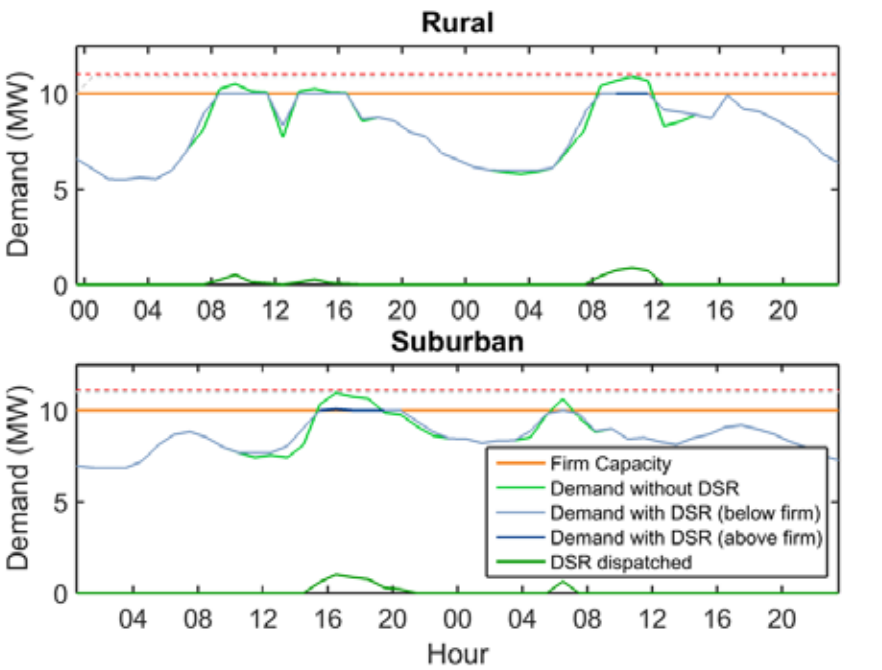
- Orange line: the firm capacity of the network for each of the representative nodes.
- Light blue-grey area: the demand on the network.
- Green lines: when demand has been shifted. This especially occurs (as per the rules of the network model) at times of outages when the demand on the network exceeds firm capacity. The demand on the network, after DSR is applied, is shown in light blue-grey (if at capacity) or dark blue (if over capacity).
- Dark blue lines: demand that DSR has been unable to reduce to firm capacity. Visible on the daily resolution charts.
- Dark green peaks at the bottom of each chart show the level of DSR activation which has been used to bring the demand on the network back to firm capacity levels.
- Dashed light red / grey lines show the total capacity (firm + DSR) available (light red) or procured for the DSO (grey).

Figure 56 – Annual DSR use on network nodes in 2025, based on demand profiles from 2009 (Rural) / 2010 (Suburban)



Source: Pöyry Management Consulting

Figure 57 – Daily DSR use on network nodes in 2025, weather patterns 2-3.02.2009 (Rural) / 3-4.11.2010 (Suburban)



Source: Pöyry Management Consulting

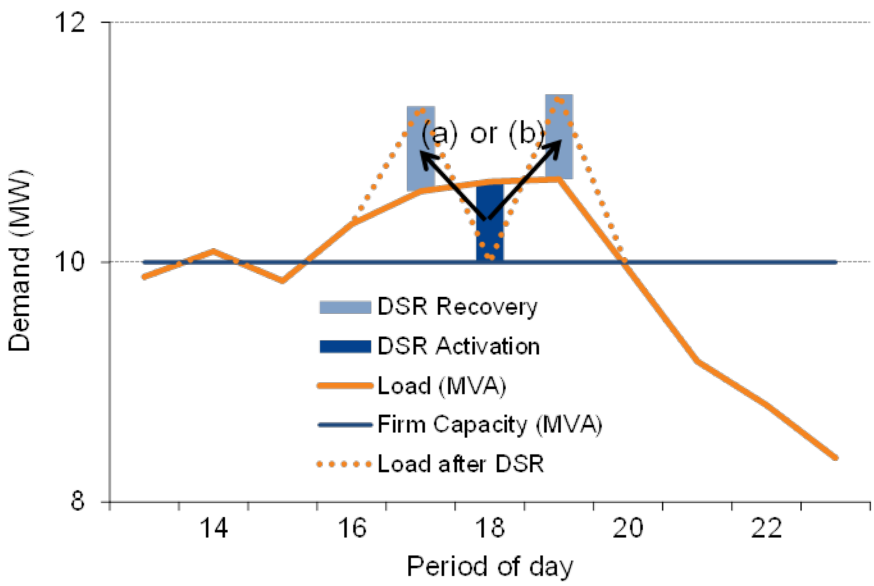
The usage patterns highlight that DSR usage by the DSO will be clustered in periods of high demand, predominantly in the coldest months of the year, and that the DSO will typically only need to procure DSR for weekdays in the winter. This is in contrast to usage by the TSO and suppliers, who use DSR throughout the year.

The daily resolution charts in Figure 57 also highlight the within-day dispatch patterns. DSR is typically dispatched in either one or both of the morning and evening peak periods, and will act to flatten out the demand profile, making the peak lower but wider. In our modelling, demand is not destroyed, and DSR is inefficient such that the recovered demand is 5% greater than the demand reduction during activation.

4.2.3 DSR utilisation and capacity benefit

The previous section shows typical usage patterns of DSR at the annual and daily levels. When load peaks are near firm capacity for an extended period (at least three hours), the use of DSR with 1 hour flexibility may not be sufficient to reduce load to or below firm capacity, as the load from the central hour cannot be shifted to a low demand period by a single call of DSR. This concept is shown in Figure 58, where 1 hour DSR has been used to address the high load in period 18 from the load profile shown earlier in Figure 53 (18 January 2013, suburban network). In this case, alleviating 0.7 MW of stress in period 18 would create a stress of 1.3-1.4 MW in (a) period 17 or (b) period 19, exacerbating the DSO's issues. Resolving such a case purely with 1 hour flexible DSR would therefore require at least 1.3 MW of DSR capacity, called multiple times.

Figure 58 – Issues with 1 hour DSR use on stressed network

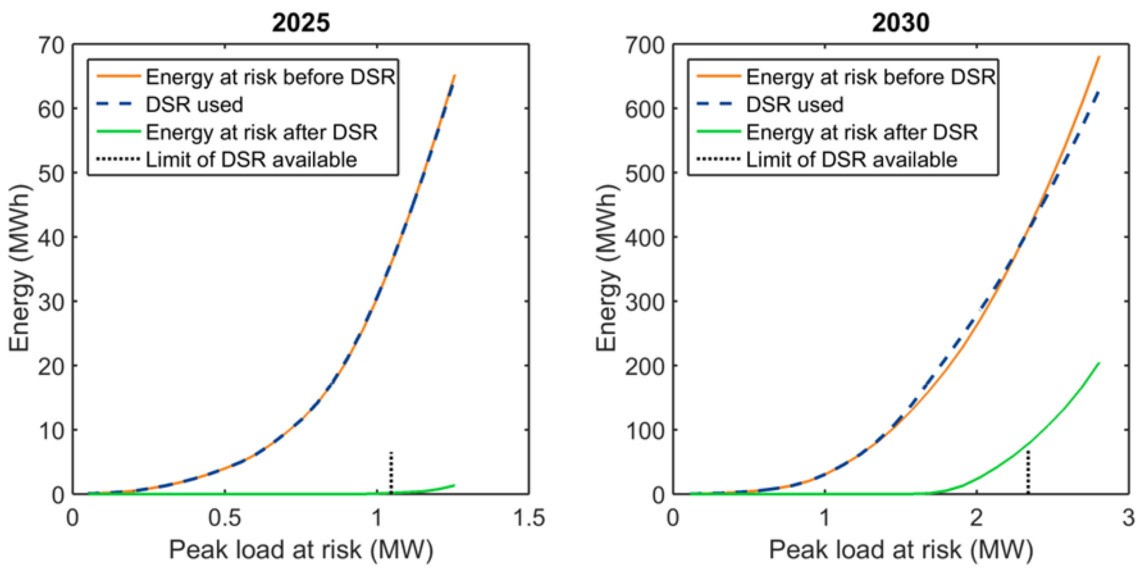


Source: Pöyry Management Consulting

In practice, most of the DSR available is assumed to have two hour flexibility, and some has 8 hour flexibility, making the situation considerably more flexible than shown in Figure 58. To investigate how much firm capacity a DSR scheme will add, we investigated how much load was left at risk for various levels of peak load on networks. Figure 59 shows the energy (MWh) 'at risk', i.e. over firm capacity, before and after the use of DSR, as well as the volume of DSR used to alleviate issues, for the rural network. The figure is scaled to assume a 10 MVA substation. All values are totals summed over one year. As peak load rises, the utilisation of DSR increases significantly above a linear rate, as the number of days DSR is called increases, along with the severity of stress on those days.

In 2025, it can be seen (up to the limit of available DSR) that little load was left at risk based on 2009 demand profile, and this was true for 4/5 historical years. In 2030, more DSR is available to use, allowing the substation to exceed firm capacity by a greater amount. Two effects become observable, that relate to the DSR having insufficient flexibility to shift demand efficiently. Firstly, for a peak load at risk above 1.4 MW, multiple DSR calls are sometimes needed to shift load at risk to non-stressed periods (similar to the example in Figure 58). This causes the volume of DSR activated to be greater than the energy at risk, as some energy needs to be "shifted" twice, requiring, for example, 2.05 MWh of DSR calls to shift 1 MWh of energy at risk. Secondly, for a peak load at risk around 1.8 MW, DSR is unable to reduce the energy at risk to zero, and hence there will be some periods where the load on the substation exceeds firm capacity. Hence, with around 2.3 MW of DSR, we can consider that the firm capacity of the substation has increased by only 1.5 to 2.0 MW. Based on the rural network data, it therefore seems that addition of extra DSR will become less effective past around 15% of firm capacity, as multiple rolling DSR calls become required to reduce demand at this level.

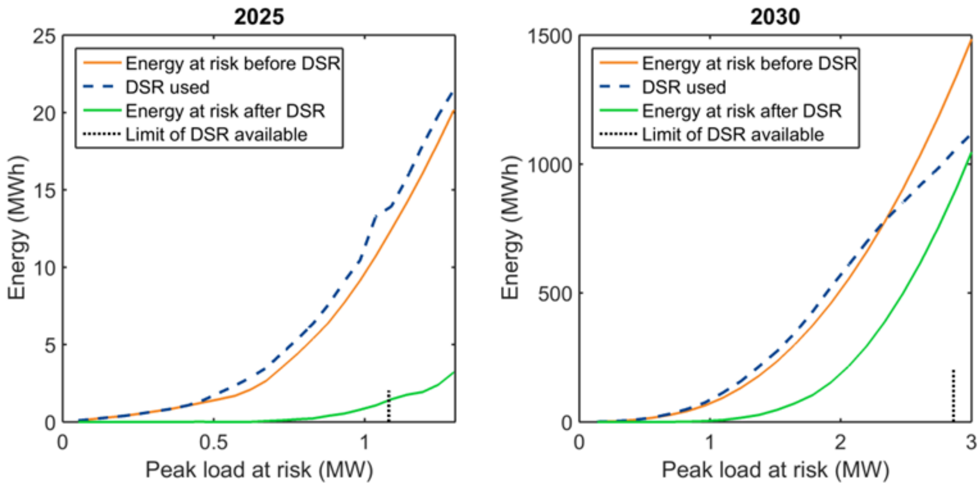
Figure 59 – DSR utilisation and energy at risk for rural node (based on 2009 demand profile)



Source: Pöyry Management Consulting

Figure 60 shows the corresponding graphs for the suburban network node based on 2010 demand profile. The suburban node data includes peaks of longer duration which are correspondingly harder for demand-shifting DSR to remove. In 2025, DSR only successfully reduces demand to firm capacity if the peak demand is 6% or less over firm capacity. In 2030, the availability of more DSR increases this to 10%, but at this level, each MW of DSR contributes less than 0.5 MW of firm capacity. Use of demand-shedding DSR (such as embedded generation, or reducing production output), which does not shift demand from one high-load period to another high-load period, may be more useful in these high-stress situations. Demand shedding DSR typically requires high utilisation rates (potentially over €200/MWh), but how significant this is depends strongly on how frequently the DSR is used.

Figure 60 – DSR utilisation and energy at risk for suburban node (based on 2010 demand profile)

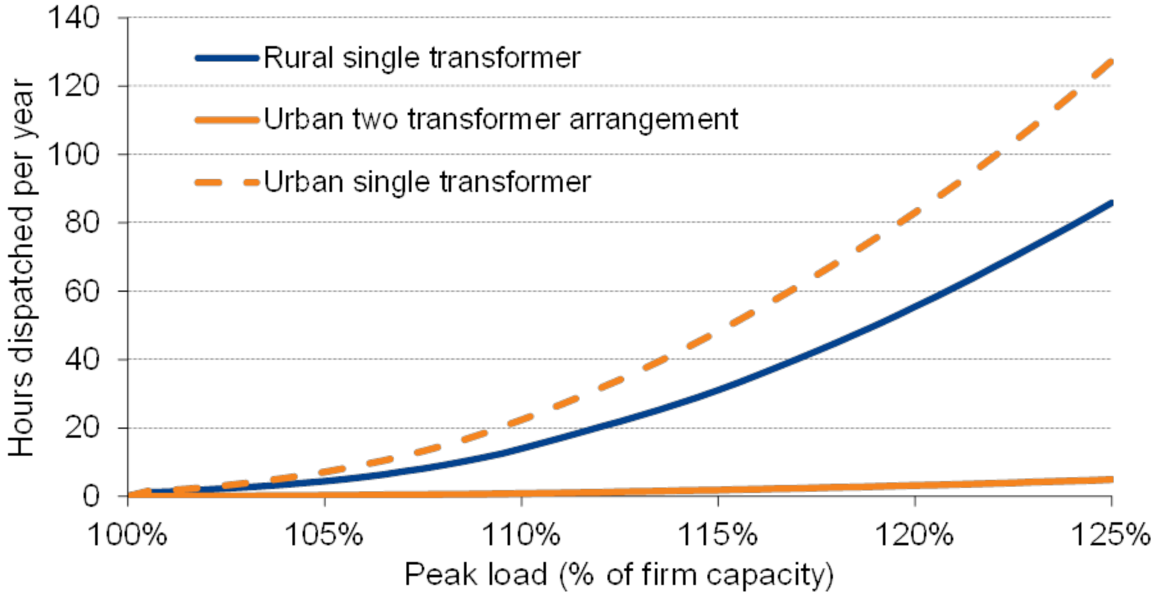


Source: Pöyry Management Consulting

The previous figures show the utilisation of DSR, assuming that it is always called when demand exceeds firm capacity. In the case of a two transformer arrangement substation, where two transformers are present to provide N-1 security in the event of a failure, this need not be the case. Considering the example of two 10 MVA transformers in parallel; this network could run with a firm capacity around 10 MVA, but, when both transformers are in service, could theoretically handle loads up to 20 MVA provided fast backup was available in the event of a failure. Provided DSR can be activated with short notification, this means that DSR can be used in a purely backup capacity, called only if there was load at risk when one of the transformers was out of service, while being available to provide N-1 security as needed. This drastically reduces the utilisation rate required for DSR, and makes sources with high utilisation costs attractive.

Figure 61 shows the average number of hours that each procured DSR source is dispatched for, across 2009-2013 weather patterns. The utilisation rate depends on the level of network stress, and in the suburban case we show rates for single transformer and two transform arrangements. For the two transformer arrangement we make the conservative assumption that it has around two weeks of unplanned outages on one transformer per year.

Figure 61 – DSR utilisation rates on two nodes (average of 5 historical years)



Source: Pöyry Management Consulting

Compared to usage by suppliers in the wholesale market, or holding in reserve, the utilisation rate of DSR by the DSO is relatively low, particularly in a two-transformer arrangement. This suggests that DSR contracted by a DSO is 'underutilised', and that cost savings would occur if the DSR can be used by another party, such as suppliers or the TSO, when not needed by the DSO. Equivalently, if the DSO is permitted to operate the DSR for non-network related activities (such as use in reserve or the wholesale market) when not required to resolve network constraints, then the additional revenue streams could be offset against the cost of acquiring the DSR.

4.2.4 Conflicts between users of DSR

Broadly speaking, if two users wish to use DSR in a local network for different purposes, there are three possible outcomes:

- Conflict: the use of DSR by one party prevents another user from using that DSR as they would wish, or exacerbates an existing problem (e.g. demand recovery shifts to a local peak-load period).
- Synergy: the use of DSR by one party assists the other, reducing their need to contract DSR of their own (e.g. supplier using DSR to reduce demand at peak load helps out the DSO).
- Neutral: the use of DSR by one party has no material impact on the other (e.g. arbitrage or reserve usage at times when the local network is not stressed).

Usage of DSR tends to be correlated between parties, particularly between DSOs and suppliers, as both use DSR to reduce peaks in demand. Because of this, previous work has suggested that synergies tend to be more common than conflicts. Figure 62 shows the results of modelling based on the UK power system, using coordinated modelling of local and national systems with matching local demand and national market data. While the required data for an equivalent analysis was not available for this project, we expect the broad trends to be similar between markets. Figure 62 shows two cases: one with no coordination between different parties, and one with simple coordination, whereby parties make allowances for DSR to be used by multiple parties on the same day. Conflicts are generally uncommon, and this is especially true with even simple levels of coordination.

Figure 62 – Example of conflicts and synergies in DSR use[31]

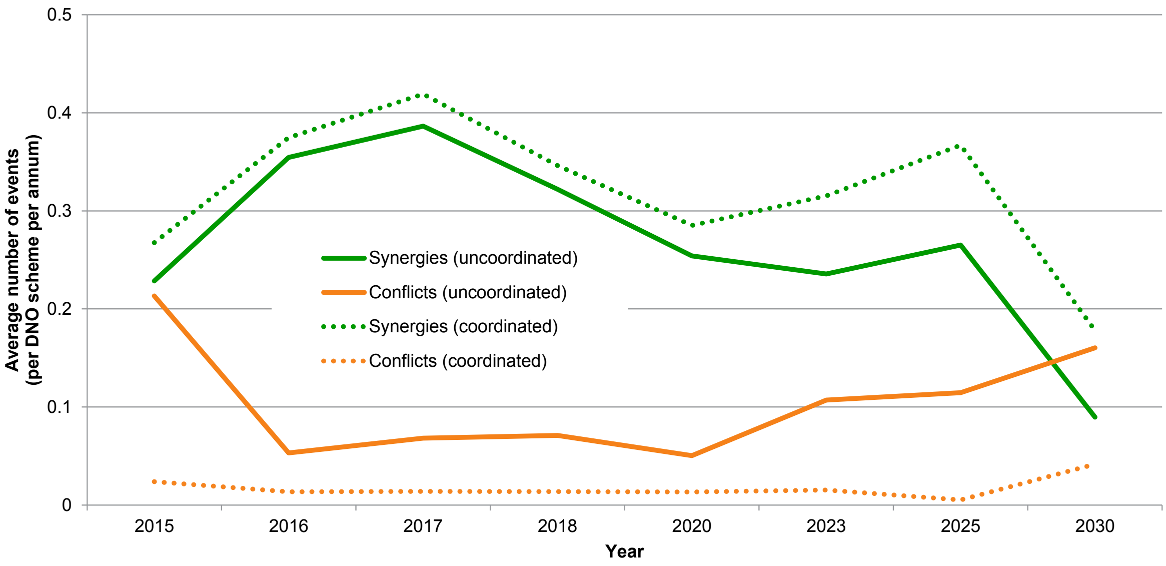


Figure reproduced from the Pöyry point of view “Demand Side Response – the myths and realities”, available at: http://www.poyry.com/news/articles/demand-side-response-myths-and-realities

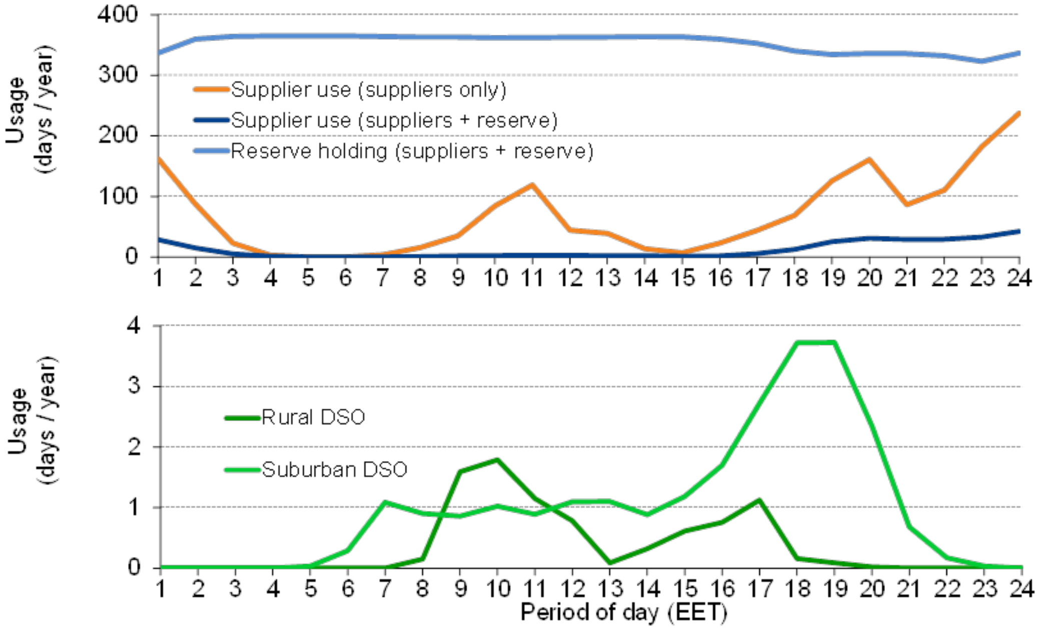
Figure 63 shows the usage patterns of different players in the Estonian market, from the BID3 modelling in section 4.1 and the network modelling in section 4.2 assuming ‘average’ stress levels on local networks. There are a few critical points to note:

- Supplier use and DSO use occur at similar times, around the morning and evening peaks.
- Supplier use lags DSO use slightly, partly due to the specific local data used, and partly by wholesale use being driven by international connections to markets with later evening peaks.
- Supplier use shifts demand later in the day, away from periods of local peak demand.
- Reserve holding occurs throughout the day, and is not correlated to DSO use.

This suggests that conflicts between the DSO and suppliers are unlikely, with supplier use either helping or having no impact on local network constraint. We would anticipate that schemes to share DSR use between these parties should therefore be promising.

[31] Based on Pöyry work for UK Power Networks.

Figure 63 – DSR calling patterns (Estonia, 2030)



Source: Pöyry Management Consulting

4.2.5 Financial benefits

In this section, we examine the possible savings at the DSO level from using DSR to defer network reinforcement due to substation constraint. We compare the use of DSR to the traditional option of reinforcing a substation.

We have made a number of base level assumptions for this analysis:

- The DSO procures DSR by season, and pays DSR providers for availability, based on the number of hours that they are available for. The DSO then need not cover the whole cost of setting up DSR schemes, as the sources of DSR are able to earn some income elsewhere.
- Availability costs are in the range 0-10 €/MW/h, for each hour that the source is contracted to be available.
- Utilisation costs are charged at €80/MWh.
- A range of annuitised reinforcement costs were tested. These values ranged from 20,000€/MVA to 60,000€/MVA (at 20,000€/MVA increments, and assume 40 year depreciation at 5% discount rate).

Economic assumptions around DSR

While demand-side response technology is in its infancy, there remains very significant uncertainty around the costs of setting up and managing different types of DSR schemes. Table 8 shows a range of cost estimates for Estonian DSR schemes, provided by Argo Rosin of Tallinn University of Technology, based on research into DSR schemes and communications with Estonian companies. The final column shows a 'weighted average cost', providing a best estimate for likely cost levels.

The specific investment costs can be converted in to national level investment costs resulting in a cumulative investment figure of between €1.6million and €110million by 2030. Using the average of the investment rate gives a cumulative investment cost of €56million by 2030.

Table 8 – Investment cost estimates for various DSR schemes

Segment	Power per load or agreement (kW)	Investment per load or agreement (k€)	Investment rate (€/kW)	Weighted average investment (€/kW)
Industry	10-1500	1-4	1-200	18
Office buildings	10-100	1-2	10-200	30
Wholesale & services	10-100	1-2	10-200	30
Residential	2-100	1-2	10-1000	75

Source: Tallinn University of Technology

In addition to the capital costs of establishing DSR schemes, their use is likely to involve fixed operational costs, to maintain equipment and personnel to run the DSR, and (depending on the type of scheme) may also attract variable operational costs covering losses associated with reducing electricity demand (i.e. utilisation costs). For evaluating financial cases, we consider a utilisation fee of €80/MWh, which we consider a top-end estimate for schemes that shift demand, and a low-end estimate for schemes that destroy demand.

The network model assumes that DSOs pay for DSR use via two payments: an availability payment paid up front, and a utilisation payment, paid when DSR is used. We assume that the utilisation fee should cover variable operational costs, while availability payments should cover a contribution to the capital and fixed operational costs. If the DSR cannot be used for any purpose other than solving local network issues, then the DSO will presumably need to cover the full capital costs, however, DSO DSR schemes should be available for other uses on days when the local network is not under stress. If regulation allows either sharing of DSR between users, or permits the DSO to operate the DSR for non-network related activities, then the DSO should be able to pay only a fraction of the full costs for setting up the DSR scheme. In the best case (from the DSO perspective), they may be able to negotiate simply paying a high utilisation fee for using DSR when required. We therefore model four availability rates: €0, €1, €3 and €10/MWh. Table 8 presents the equivalent capital cost that these fees would cover (not including any payments from other activities) under a range of possible financial scenarios.

Table 9 – Equivalence of capital costs and availability payments

Availability price (€/MW/h)	Scheme details	A	B	C
	WACC	5%	5%	12%
	Months available per year	6	4	4
	Economic lifetime	15	12	8
		Equivalent capital cost		
0		0 €/kW	0 €/kW	0 €/kW
1		11 €/kW	6 €/kW	3 €/kW
3		32 €/kW	18 €/kW	10 €/kW
10		110 €/kW	60 €/kW	34 €/kW

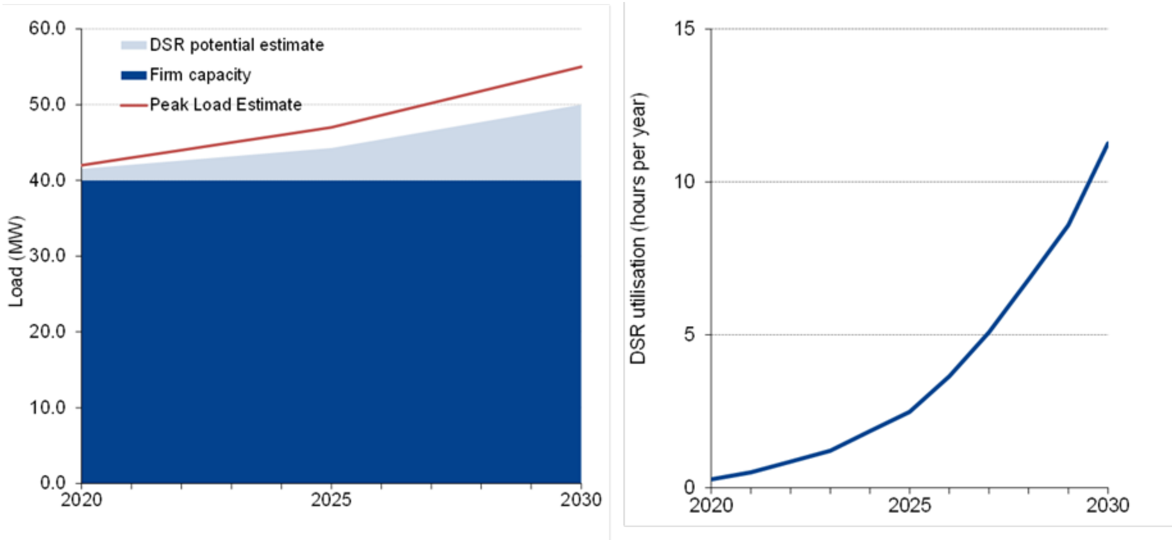
Equivalence between capital costs (€/kW) and availability price (€/MW/h), assuming payments for 40 hours per week for a certain number of winter months per year.
Source: Pöyry Management Consulting

Comparison of Table 8 and Table 9 suggests that availability payments around €10/MW/h should, in time, cover the full cost of establishing DSR schemes, and long term schemes financed at the DSO cost of capital (~ 5%) may even be closer to the €3/MW/h mark. Payments below €10/MW/h, particularly if DSR is being financed privately, assume that sharing allows the DSO to pay only part of the setup costs of the DSR.

Example substations

Our analysis shows that availability prices are the most important potential savings for the DSO on two transformer substations, as even an availability payment of €1/MW/h represents a significantly greater cost than the utilisation payments. Figure 64 shows the forecast load, current capacity and assumed national average available DSR, for an urban substation, based on existing substation data. This substation is a two transformer arrangement, each of 40MVA capacity, but the analysis here can be considered to be typical of a wide variety of two transformer substations, provided the forecast load exceeds capacity by an amount that is manageable by DSR.

Figure 64 – Forecast load and DSR utilisation for a two transformer, 40 MVA 10kV urban substation



Source: Pöyry Management Consulting

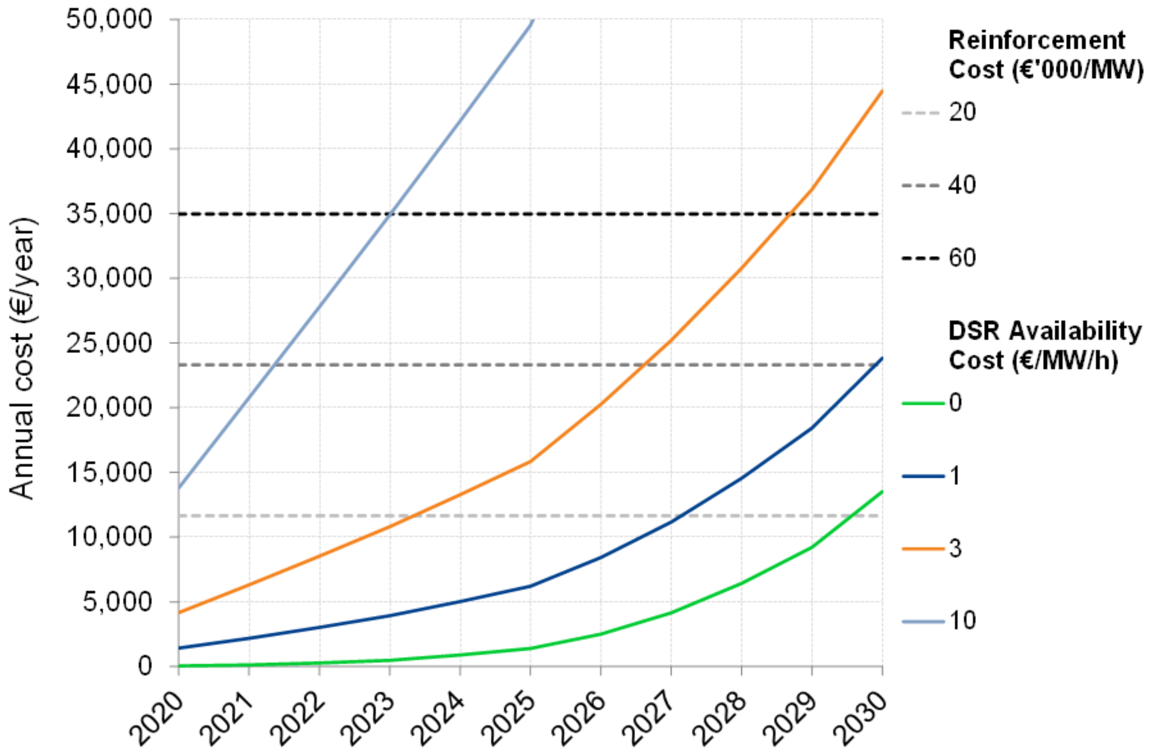
The assumption is that this substation is already in a state where there is load at risk and either reinforcement needs to be made in the immediate short term, or DSR has to be used in order to delay this reinforcement beyond the present time. Figure 65 shows the annual costs for this substation (€/year basis). The dashed grey lines show a case when no DSR is procured and therefore reinforcement needs to occur immediately. Here we assume reinforcement takes place in a 10 MVA block, and the equivalent annual cost to the DSO is the annualised reinforcement cost, which (at €40,000/MVA) equates to approximately €23,000/year.

The solid coloured lines show instances when sufficient DSR is procured to manage the constraint, at 4 different availability prices (€0, €1, €3 and €10/MW/h). The DSR is assumed to be dispatched when an outage is present on the substation, each day of the year has a 1 in 26 chance of an outage being present (equivalent to an average of two weeks per year), and utilisation costs are paid only when DSR is dispatched.

For availability costs below €10/MW/h, procuring DSR is significantly cheaper than reinforcing the network for a multi-year period. Figure 66 shows the value of savings accrued to 2030, at different availability prices, assuming that DSR is used until reinforcement is the cheaper option, and that reinforcement then takes place. Cheaper availability costs result in both greater savings per year, and schemes that exist for a greater period of time before reinforcement takes place. This figure highlights the value of sharing DSR resources, given that €10/MW/h is a rough proxy for the cost of fully supporting a DSR scheme, while cheaper rates should be possible when a DSR resource is used for multiple purposes. In this instance, cheaper utilisation rates (below the €80/MWh assumed) will not significantly improve the benefits, as the majority of costs come from availability payments (unless they are < 1 €/MW/h).

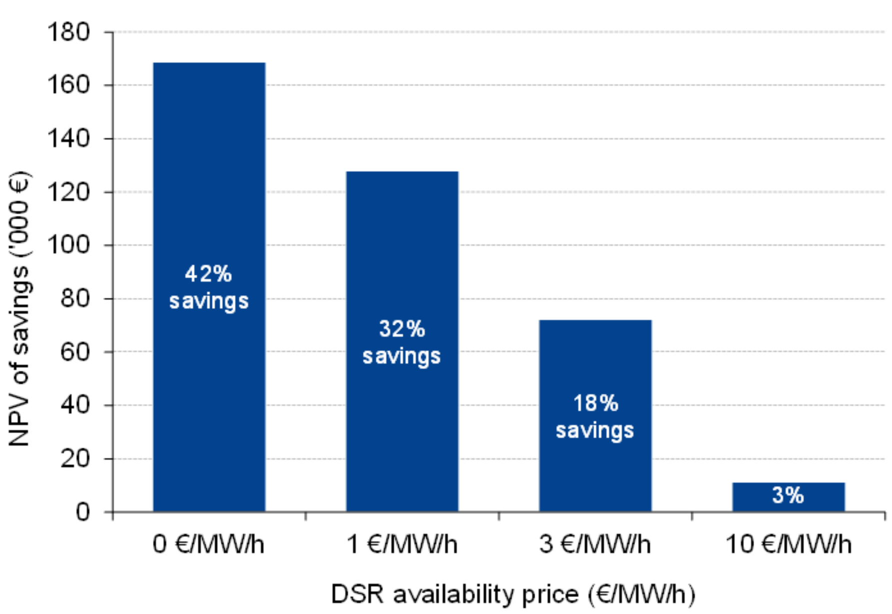
In general, single transformer substations will be less economically viable for a DSO to use DSR, if they are paying a significant utilisation cost for the DSR. Savings are, however, still possible in cases where the reinforcement cost is significant and the forecast load is not too far past firm capacity.

Figure 65 – DSR vs reinforcement costs, two transformer, 40 MVA 10kV urban substation



Source: Pöyry Management Consulting

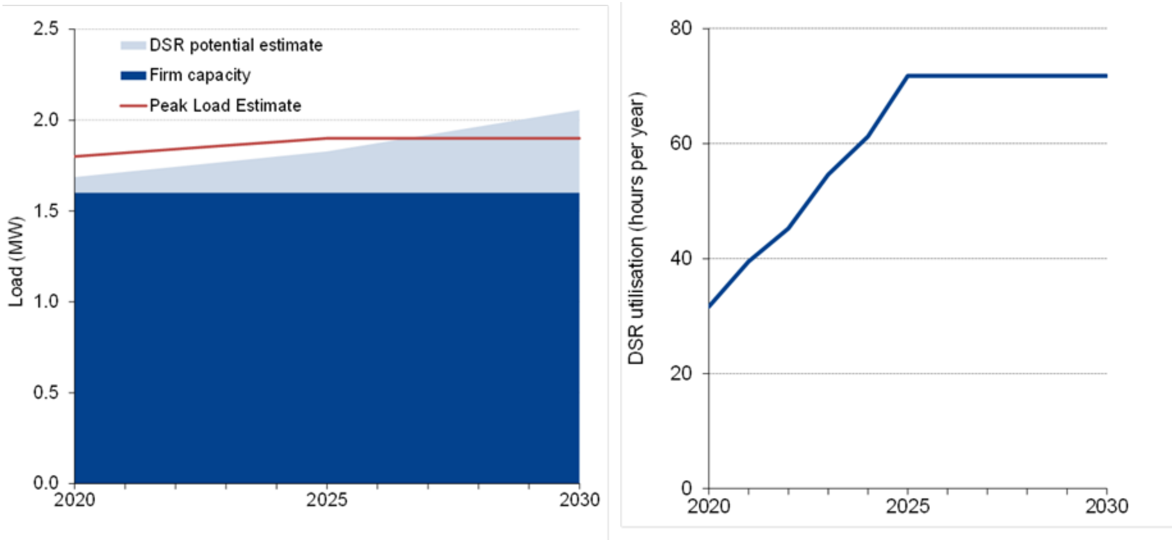
Figure 66 – Financial benefit of a DSR scheme, 40 MVA 10kV urban substation



NPV of savings made by implementing a DSR scheme up to the point when reinforcement becomes the cheaper option. Figures assume comparison to 10 MVA reinforcement at €40,000/MVA (middle dashed line in Figure 65). White inset text shows the savings as a percentage of the cost of reinforcement.
Source: Pöyry Management Consulting

Figure 67 shows the forecast load, current capacity and national average available DSR, for a small (1.6 MVA) rural substation, based on an existing substation data. Cost and utilisation figures again assume that sufficient DSR is procured to allow peak load to be reduced to firm capacity.

Figure 67 – Forecast load and DSR utilisation for a single transformer, 1.6 MVA rural substation



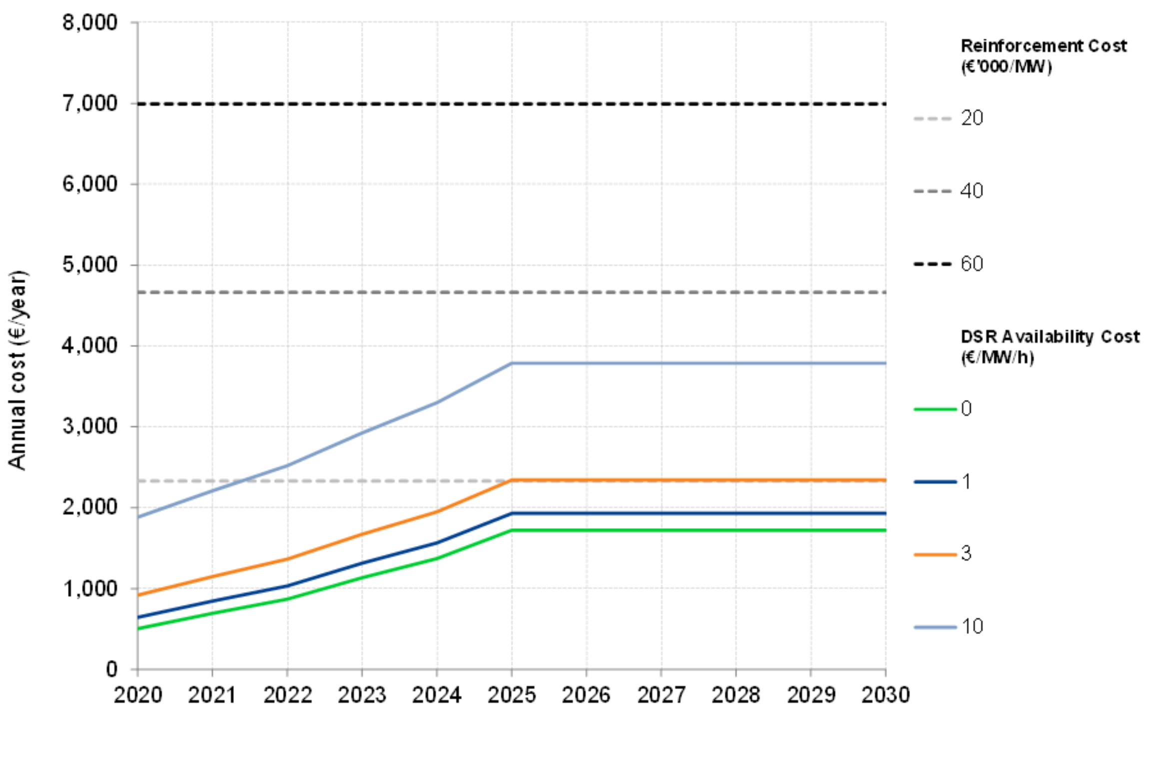
Source: Pöyry Management Consulting

Figure 68 shows the annual costs for this substation (€/year basis), compared against the reinforcement cost, assuming a 2 MVA block, with an equivalent annualised reinforcement cost that (with reinforcement at €40,000/MVA) equates to approximately €4,700/year.

The solid coloured lines show instances when sufficient DSR is procured to manage the constraint, at 4 different availability prices (€0, €1, €3 and €10/MW/h). In this instance, utilisation payments are significant, which is reflected in the fact that the cost of a €0/MW/h is only slightly below half the cost of a €10/MW/h scheme. In this instance, low-utilisation rate sources of DSR may be preferred if they can be procured. Procuring DSR sources with utilisation rates below €80/MWh (as assumed here) would significantly improve the economic benefit.

Under the combination of assumed costs and forecast loads, this DSR scheme is attractive as a semi-permanent arrangement, to be reviewed in future if the load forecasts change. Even at €10/MW/h and €80/MWh, the cost of paying for ongoing use of DSR is 20% cheaper than an upfront payment to reinforce the substation. While we are using generic figures for costs and benefits, this suggests that there should be cases where such schemes result in savings that are a significant fraction of the avoided reinforcement costs.

Figure 68 – DSR vs reinforcement costs, single transformer, 1.6 MVA rural substation



Source: Pöyry Management Consulting

4.3 Summary of findings

The socio-economic value of DSR to the Estonian system can be categorised by national level benefits; i.e. savings from using DSR for wholesale market savings i.e. day-ahead, within day and balancing, system services and security of supply, and local level benefits; i.e. savings from using DSR to alleviate or eliminate local network issues.

National level

- While DSR can be used for the purposes of optimising wholesale market costs in Estonia, the associated value of using demand-side response for this purpose is fairly low, although it does increase over time corresponding to annual benefits of around €0.5m/yr in 2020, €1.0m/yr in 2025 and €3.0m/yr in 2030. The relatively low value is due to the relative size of the Estonian market to interconnection and the flexibility of the Nordic system which drives flat prices.
- Uses of DSR for the within-day or balancing timeframe will increase due to increased wind penetration, but only to a limited extent, given the flexibility of the neighbouring Nordic system (and based on the assumption that effective ways are found of sharing flexibility across interconnectors in intraday and balancing timeframes). Therefore the total market size is estimated to remain the same as today.
- When Estonia desynchronises from IPS/UPS, it will need to hold additional reserves. At that time, DSR could play a key role in the provision of holding reserve and deliver significant cost saving potential for the Estonian system through avoided investment costs. The value associated with the use of DSR for holding reserve is relatively high, especially compared to the wholesale market use of DSR – the annual market value

of DSR for reserve provision is estimated at €14.4m. This is because using DSR to hold reserve can stop Estonian plant from part loading and/or investment in plant to provide reserve. This also lowers Estonian CO_2 emissions[32]. In addition, using DSR to hold reserve can avoid the need to invest in a new gas engine. The avoided cost is estimated at €68million. Importantly, this finding rests on the assumption that Estonia must provide all its reserve from internal sources. Provision of reserve from neighbouring markets could reduce the overall value associated with reserve provision in Estonia.

- DSR can make a meaningful contribution to Estonian security of supply by compensating for decreasing firm capacity and increasing demand on the Estonian system.

Local level

DSR can provide value to the Estonian distribution system through relieving network constraint and allowing network investments to be deferred. The DSO that took part in this study is expecting that 10% of local substations will need to be reinforced by 2025. DSR may be able to help in managing peak loads and network security.

For the case we have investigated; i.e. using DSR to defer substation reinforcement costs; DSR is only considered in cases where forecast peak load is above the already existing substation capacity, but where the load is not so high that reinforcement is the cheaper or only technical option. This means that DSR schemes tend to only be considered at a small fraction of sites on the distribution network. For these sites, we note the following key points:

- If DSR is readily available, and can be secured cheaply and reliably by a DSO, then there is potential for DSR use to allow a lower capacity, cheaper distribution network.
- DSR utilisation rates by the DSO are low, particularly for two-transformer arrangements, and concentrated in peak winter days.
- There are a limited number of substations (< 10% of the total number) where DSR may be relevant in the next decade. The data provided does not enable us to take a position on whether this is front or back loaded but the use of DSR (if available) can be considered immediately where there are substations being reinforced or replaced. Some of these sites could be potential trials for DSR.
- There may be some sites where it is economically beneficial for the DSO to procure DSR solely for network use.

[32] Compared to a baseline where DSR is not available

5. RECOMMENDATIONS

The previous chapters of this report have highlighted the potential role and value that DSR can bring to the Estonian market and quantified, at a high level, the value associated with using DSR in the Estonian market.

If it is decided that DSR should play a role in the Estonian market in the future, a key challenge will be 'how' DSR can participate in the Estonian market. The following sections outline these implementation challenges and the recommendations to solve the challenges.

5.1 Market and regulatory framework

This study has identified numerous market and regulatory issues that need to be addressed in order to integrate DSR into the Estonian system:

- Estonia should incorporate core requirements of the RfG and the DCC EU Network Codes as well as of the EU directives (e.g. energy efficiency directive) and policy documents (e.g. communication on Energy Union) in respect of the connection of generation and the use of demand-side response by making appropriate modifications to the Electricity Market Act and the Grid Code.
- The nature of the Estonian DSR resource i.e. significant commercial and household potential means that aggregators will play a key role in developing DSR in Estonia. Therefore regulation should be modified to enable aggregators to participate across all markets. In addition, careful consideration should be given to the challenges DSR may face when bidding for a service that has been designed with generation in mind.
- Much of the DSR potential in Estonia appears to be located on the distribution network. DSR appears to have value to the DSO in the shorter term while in the longer term value is higher to the TSO. Therefore, the interface between the TSO and DSO will be important and a framework for interacting should be considered. Moreover, most DSO schemes will require sharing of DSR use (for the wholesale market or reserve) to achieve a significant economic benefit. If this occurs, there is scope for significant savings in network investment if appropriate sharing schemes and/or regulations are in place. Therefore regulation should ensure that DSR may either be shared by multiple parties, or that a DSO is allowed to use DSR resources for market trading or reserve when they are not needed for supporting the distribution network.
- The existing regulatory incentive framework needs to be reconsidered for DSR use. To the extent that DSR avoids the need for network reinforcement, the incentive arrangements for the DSO must ensure that economically efficient decisions are rewarded. This means to reward the use DSR where it delivers the most economically efficient solution, whether that is reducing operating expenditure (OPEX) – currently a pass through item[33]) – or where it leads to more efficient investments (CAPEX) decisions e.g. deferring investments in transformers. The caveat is that regulation should probably still promote measures to increase security of supply (such as undergrounding) which require CAPEX spend. One example

[33] Uniform Methods for Calculating Electricity Network Charges, Estonian Competition Authority, 2014

incentive framework is the current regulatory framework for distribution networks in GB (RIIO-ED1[34]).

5.2 Potential for shared development

DSR in Estonia faces a development challenge. In the long term, desynchronisation will increase reserve requirements in the Baltics and this could be the key value driver for DSR. Although this will not become a reality until 2025, then for preparedness and testing purposes it will be needed even sooner – the Baltics need to demonstrate the ability to operate as an isolated system. The important issue is to design a scheme that allows a transition between the different uses of DSR.

In the shorter term, the value associated with DSR appears modest and localised to the DSO. Such schemes can achieve large cost savings but the volume is likely to be low (some 10% of substations have been identified as suitable for investment deferral). Supplier driven DSR is also likely to be limited in the short term. This situation lends itself to a smaller and simpler DSR scheme that could be activated quickly.

To achieve the necessary level of reserve provision from DSR by 2025, a period of familiarisation and learning of several years is required before the potential can be realised as the scheme will be technically challenging and potentially more demanding for DSR providers.

When coupled with the finding comment that the services (generally) complement rather than contradict. This means that DSR could be rolled out (led by the DSO or with the DSO and another party to share the costs) in advance of replacement of substations and this could be done in a way which permits use of the same resources by the TSO at a later point, including in a trial period as a proof of concept in advance of desynchronisation. If this is to be the case, it should be noted that the scale of DSR needed by the TSO is much bigger than a DSO is likely to fund.

5.3 Areas for further research

- Understanding and quantification of the potential for a proportion of Estonian reserve requirements to be provided by neighbouring markets. Given the relatively high value associated with reserve provision from DSR, it is recommended this is investigated.
- Understanding and quantification of the expected network investment requirements for DSO in Estonia over time and location.
- DSR mapping to identify where DSR can be deployed on the network and over what timescale. This analysis has not modelled every transformer on the DSO network but rather 10kV transformers on representative networks. There could be additional savings associated with the use of DSR (to be quantified) extending the analysis to cover higher and lower voltage transformers on the distribution network and other types of use of DSR for the DSO.
- Further investigation and quantification of demand destruction potential from DSR.
- Investigation and quantification of backup generation that could be used for DSR or as part of a VPP such as emergency generators in hospitals or data centres.
- Studies to better understand the cost of deploying DSR in Estonia as the range of costs is significant.

[34] https://www.ofgem.gov.uk/network-regulation-riio-model/riio-ed1-price-control

- A thorough technical review needs to be carried out to verify the ability of Estonian DSR to meet reserve requirements.

ANNEX A – ABBREVIATIONS

AGC	Automatic Generation Control
BEMIP	Baltic Energy Market Interconnection Plan
BRELL loop	Transmission networks of the power systems of Belarus, Russia (Central and North-Western parts), Estonia, Latvia and Lithuania
BRP	Balance Responsible Party
BSP	Balance service provider
CAPEX	Capital expenditure
CE	Continental Europe
CEER	Council of European Energy Regulators
CoBa	Coordinated Balance Area
DCC	Demand Connection Code
DSBR	Demand Side Balancing Reserve
DSM	Demand-side Management
DSO	Distribution System Operator
DSR	Demand-side Response
DUoS	Distribution Use of System
ELMO	Electromobility
ENTSO-E	European Network of Transmission System Operators for Electricity
EV	Electric vehicle
FCR	Frequency Containment Reserve
FRR	Frequency Restoration Reserve
I&C	Industrial and commercial
ICT	Information and communication technology

mFRR	Manual Frequency Restoration Reserve
OPEX	Operating expenditure
OTC	Over the counter
RE	Renewable energy
RfG	Requirements for Generators
RPM	Regulating Power Market
RR	Replacement Reserve
SEDC	Smart Energy Demand Coalition
STOR	Short Term Operating Reserve
TNUoS	Transmission Network Use of System
ToU	Time of use
TSO	Transmission System Operator
UCTE	Union for the Co-ordination of Transmission of Electricity
UES / UPS	Unified Energy System / Unified Power System
VPP	Virtual Power Plant
WPDRS	Winter Peak Demand Reduction Scheme

ANNEX B – CHALLENGES IN OPTIMISING THE USE OF DSR

B.1 Challenges in optimising the use of DSR

There are a number of challenges in optimising the use of DSR:

- Development of DSR will result in modifying the role and responsibilities of DSR providers.
- Potential uses / benefits (and hence revenues) for DSR come from a variety of sources. Some of the benefits are accessible to DSR and some are not.
- DSR brings together existing and new stakeholders that do not currently have formal market or technical relationship.
- DSR capabilities are evolving. Not all potential providers of DSR can realise this potential. Further, there are significant learning and technical challenges to be overcome. This means given the right incentives, DSR provision will grow over time.

The development of DSR requires the modification of the role and responsibilities of DSR providers. DSR will be provided by distributed generation, industrial and commercial loads and residential loads. In order to provide DSR for certain uses, such as reserve, (aggregated) loads will need to comply with rules and requirements originally meant for owners of generation units.

The use of DSR in serving multiple purposes for multiple different stakeholders (TSO, Supplier, DSO etc.) gives rise to a number of challenges and to potential conflicts and synergies in the use of a particular candidate resource by various parties.

Various DSR uses may sometimes be aligned or may on occasion be in conflict with each other depending on the hierarchy of utilisation of the DSR resource between the various parts of the value chain. Without an appropriate regulatory and market framework governing the use of DSR by multiple parties, end consumers may receive conflicting signals (whether instructions or prices). It is therefore essential to understand those instances when conflicts as well as synergies may occur.

In addition, the timeframe in which DSR will be used by various parts of the value chain naturally gives rise to potential conflicts:

- Suppliers will use DSR within-day (period between day-ahead and gate closure) to re-align their positions.
- The TSO uses DSR for reserve purposes.
- The DSO will use DSR to tackle planned outages and unplanned outages as well as critical peak scenarios. Requirements for planned outages are given significant notice. For unplanned outages, DSR will need to be called sufficiently quickly to prevent a circuit trip or risk of unacceptable loss of asset life due to thermal stress on network components.

The different timeframes in which DSR is used by various parties leads to synergies and conflicts in the way in which DSR may be dispatched and how a particular DSR resource may be a candidate for one or more resources. These issues need to be linked to potential commercial frameworks which could be implemented.

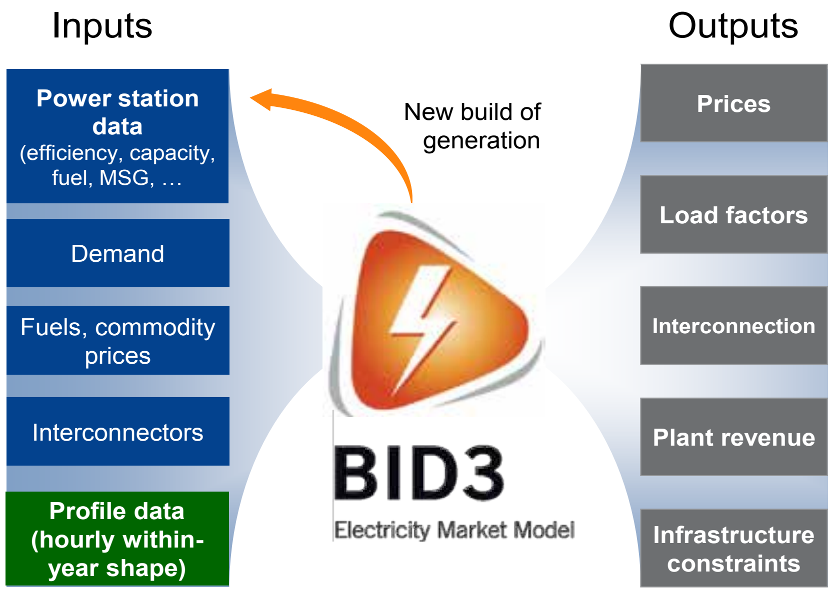
The varying volumes in the use of DSR (e.g. use for local (DSO) issues versus national level issues) also provide interesting insights in relation to the price signals (payments) which would be needed for various parties (e.g. DSOs) to competitively procure their DSR requirements compared to the TSO. Some revenues are market based, some revenues are based on avoided costs, and some revenues are based on regulated revenue streams.

ANNEX C – BID MODEL

C.1 Model overview

Figure 69 describes at the high level the inputs and outputs of the model.

Figure 69 – Overview of BID3



C.1.1 Principles of the model

BID3 is an economic dispatch model based around optimisation. The model balances demand and supply on an hourly basis by minimising the variable cost of electricity generation. The result of this optimisation is an hourly dispatch schedule for all power plant and interconnectors on the system. At the high level, this is equivalent to modelling the market by the intersection between a supply curve and a demand curve for each hour.

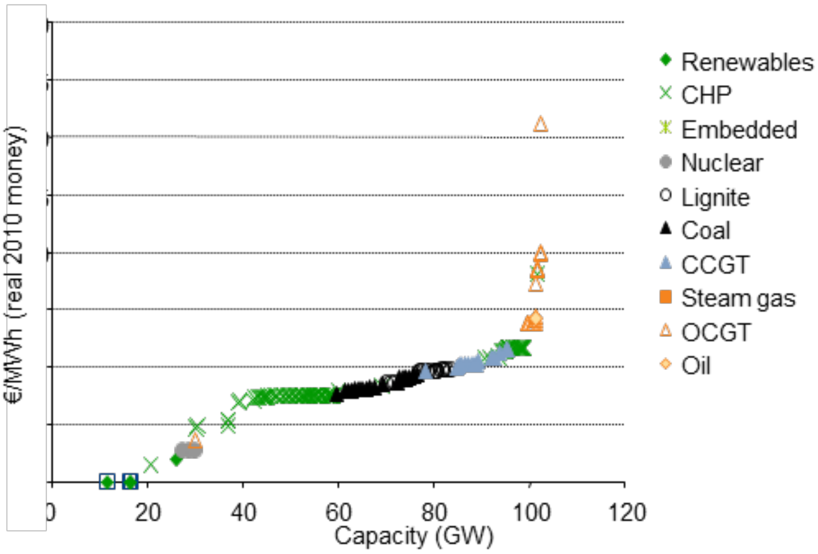
C.1.2 Modelling the system schedule

- **Dispatch of thermal plant.** All plants are assumed to bid cost reflectively and plants are dispatched on a merit order basis – i.e. plants with lower short-run variable costs are dispatched ahead of plant with higher short-run variable costs. This reflects a fully competitive market and leads to a least-cost solution. Costs associated with starts and part-loading are included in the optimisation. The model also takes account of all the major plant dynamics, including minimum stable generation, minimum on-times and minimum off-times. Figure 70 shows an example merit order curve for thermal plants.
- **Dispatch of hydro plant.** Reservoir hydro plants can be dispatched in two ways:
  - a simple perfect foresight methodology, where each reservoir has a one year of foresight of its natural inflow and the seasonal power price level, and is able to fix the seasonality of its operation in an optimal way; or
  - the water value method where the option value of stored water is calculated using Stochastic Dynamic Programming. This results in a water value curve

where the option value of a stored MWh is a function of the filling level of the reservoir, the filling level of competing reservoirs, and the time of year.

- **Interconnector flows.** Interconnectors are optimally utilised – this is equivalent to a market coupling arrangement.

Figure 70 – Thermal plant merit order



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