Energy storage using conventional hydropower facilities

S.M. Allen, Vice President, Stantec, USA

As the world transitions towards decarbonizing electricity production, the use of renewables remains an important topic as an integral part of this energy transition. Renewable energy can help decarbonize electricity production but requires other technologies, such as storage, to meet demand reliably. Taking three example, this article demonstrates the value of conventional hydropower reservoirs in acting as 'hydro batteries'.

It has been estimated that energy storage capital costs of less than \$20/kWh would be necessary to enable cost-competitive baseload power to be provided by renewable sources such as wind and solar power. Unfortunately, energy storage costs are currently estimated at around \$400/kWh or more for battery systems, and around \$200 to \$300/kWh for pumped-storage systems. While battery storage costs are declining, it seems unlikely that they would decline to only 5 per cent of current costs in the foreseeable future.

A possible solution to get at least part of the way there (to something on the order of \$60 to \$75 Capex per kWh storage capacity, based on available data) lies in the use of conventional hydropower, which is operationally regulated to mesh with output from solar and wind generation. A modest-sized hydropower reservoir can act as a dispatchable integrated generation systems (DIGS) cost-effectively, because of its ability to store energy in the form of water in the reservoir, referred to as the 'HydroBattery'. This concept can be used in conjunction with land-based solar, floating solar and wind power.

The approach works by ramping down conventional hydropower facilities (assets that are already economically supported based on their electricity generation and other benefits) when solar and/or wind output is substantial, and ramping up when this is not the case. Thus, additional costs for energy storage (in this case, in the form of water in the reservoir) are minor, and may be in the range required to support the widespread adoption of solar and wind power.

The DIGS approach leverages existing investments in hydro facilities so that they can produce more energy and store grid energy without losses; hydro is the only technology with this ability. This should be compared with other storage systems which lose 15 per cent or more of the energy stored.

By examining three specific conventional hydropower plants, ranging in size from 5 MW to 400 MW, we can estimate the additional energy that can be generated by adding a solar component, while in effect storing energy in the reservoirs for later use when the solar arrays are not producing power.

1. The approach

As grid systems proceed to convert to an all-renewable energy generation mix, and as renewable sources such as wind and solar become more and more economical, the need to store energy from these non-dispatchable sources, and to provide consistent power quality (with respect to voltage and frequency) has emerged as the key challenge for the decade of the 2020s. Fig. 1, from the US Department of Energy's Idaho National Laboratory (INL), summarizes the essential benefits of this smart approach to energy storage.

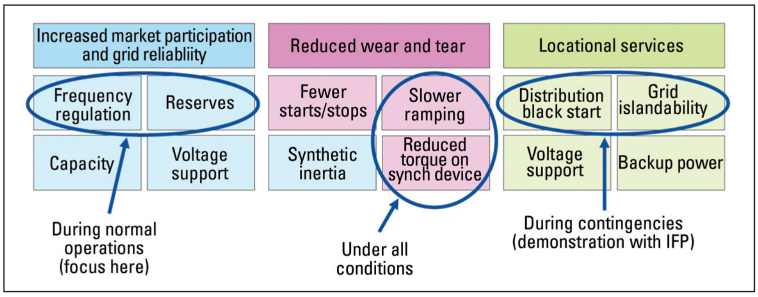


Fig. 1. The benefits of dispatchable integrated generation system (DIGS).

It is widely understood that, as photovoltaic (PV) and wind capacity increase, the value of storage will also grow. Conventional hydropower can effectively store very large amounts of energy in the form of water in the reservoir, when managed effectively and using the right combination of engineering, hardware and software.

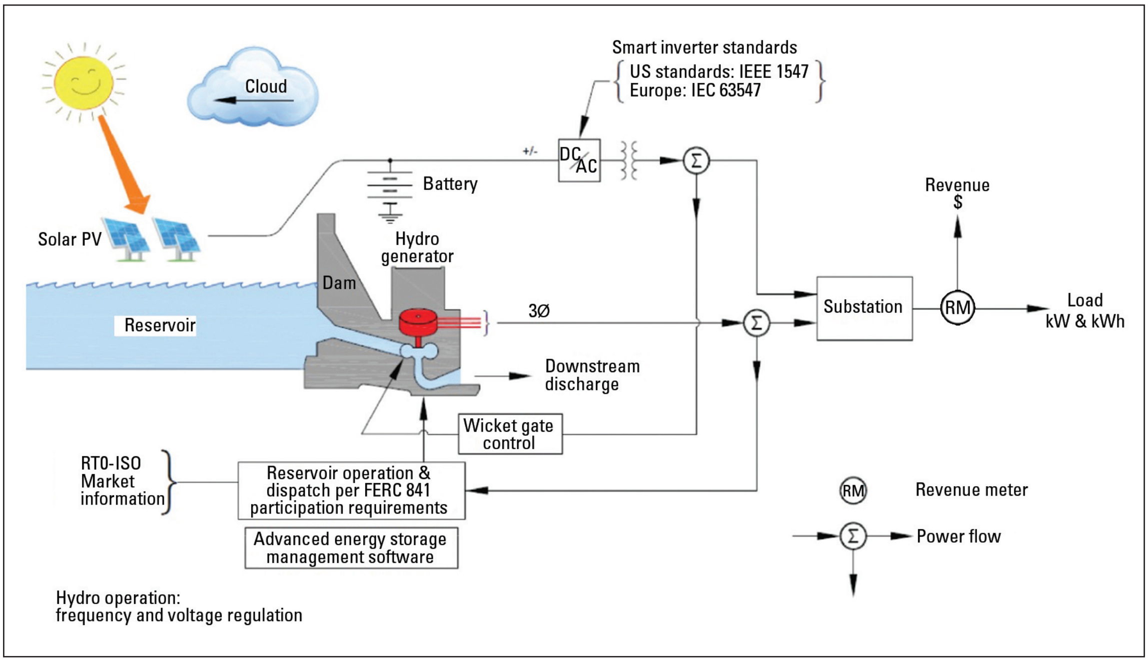
One interesting aspect of the research into energy storage is that it turns out that there are several additional benefits to be gained when one integrates a storage system based on conventional hydropower with other renewables and a battery. In addition to the important services noted in Fig. 1, it is possible to include solar generation (that is, floating solar) with the hydro facility, so that the powerplant owner now has, in effect, a microgrid providing:

- more energy than the hydro facility alone could produce;
- more resilience with respect to mitigating droughts [Donalek *et al*, 2018[1]];
- more resilience with respect to responding to local or grid upset conditions;
- more resilience with respect to normal (mean) hydrological seasonal variations; and,
- greater ability to respond to dispatch requests from the grid operator.

Taken together, the benefits noted in the INL graphic and the additional possibilities listed above should allow owners of many existing hydropower facilities to increase revenues in a cost-effective way. In this paper we explore very approximate costs and benefits based on available data for a small hydropower facility (5 MW), a medium-sized one (50 MW), and a larger one (400 MW). We refer to such a system as a dispatchable integrated generation system (DIGS).

Note that interconnection of battery energy storage systems (BESS) is primarily governed by IEEE 1547-2018 and IEEE P2800 (under development); compli-

Fig. 2. The DIGS concept.



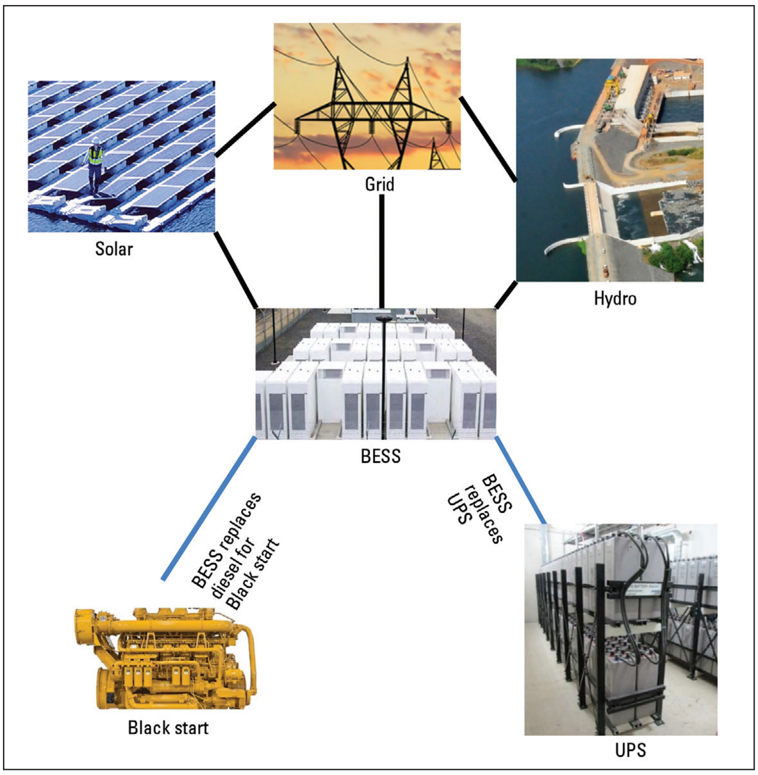
ance with these requirements will be part of the necessary engineering work. Figs. 2 and 3 illustrate key features of the DIGS/ HydroBattery approach.

2. Assumptions

The following assumptions are made based on data currently available in 2021.

• *Cost of engineering for DIGS*: of the order of \$150 000 for a small facility, and around \$400 000 for more for a large facility.
• *Cost of permitting*: Not included as this is highly variable, and may be nominal in some cases.

Fig. 3. Uses of BESS.



• *Cost of floating solar array*: About \$1000/kWe capacity including PV panels, inverters, floats and anchorage system.
• *Area required for floating solar array*: About 1 ha/ MWe of capacity.
• *Cost of additional electrical equipment (power conversion system):* \$55/kW of battery capacity, based on 4 h of storage (does not include battery).
• *Cost of additional electrical equipment (balance of plant):* \$172/kW of battery capacity based on 4 h of storage (does not include battery).
• *Battery capacity (MW)*: equal to 10 per cent of capacity of the hydro plant, to reduce wear and tear on the hydro equipment, and to provide/ enhance ancillary services (voltage and frequency support).
• *Battery energy storage (MWh):* Equal to full battery capacity for 4 h.
• *Battery efficiency (output MWh divided by input MWh):* 85 per cent. Thus, a 2 MWh battery yields only 1.7 MWh when it is discharging.
• *Solar power capacity (MWe):* Equal to the capacity of hydro plant.
• *Battery system installed*: About \$400/kWh of energy storage.This figure will also be used as a rough indication of the value of a grid-scale energy storage system.
• *Energy wholesale price for stored energy*: Averages \$100/MWh and extends for 4 h/lday.
• *Site-specific hydrology and permits*: These are suitable to support use of the reservoir as an energy storage device as described herein.

3.Examples

3.1 Box Canyon hydro plant, California

This 5 MW plant, in Siskiyou County, California, has a reservoir with a surface area of about 174 ha and a total volume of about 32 × 10^6 m^3.

The dam was completed in 1970, and an innovative powerhouse was installed in 1984 beneath the spillway. As noted in the Upper Sacramento, McCloud, and Lower Pit Watersheds Integrated Regional Water Management Plan [USR and IRWMP, 2018[2]], "Box Canyon dam, run by the Siskiyou Power Authority, has a mandate for temperature, dissolved oxygen, and flow into the river below the dam Upper Sacramento, McCloud, and while there has never been a problem with the dissolved oxygen and temperature (the water is pulled from deep in the reservoir, maintaining a cool temperature, it then runs through the power production mechanism, which substantially increases the dissolved oxygen content), the outflow required is more than the inflow during most summer months. It is possible that, because of projected climate effects on regional hydrology (more frequent droughts and more variable precipitation), the flow mandate for Box Canyon dam will become increasingly difficult with which to comply."

The above information is an example of the sort of site-specific considerations that would need to be dealt with before changing the operating regime of a hydropower plant to take advantage of its possibility to store energy and provide additional ancillary services. If, however, the required operational flexibility can be confirmed, two scenarios for considering a DIGS implementation at Box Canyon arise as discussed below.

There appears to be more than enough area in the reservoir to deploy floating solar PV with a capacity about equal to that of the hydropower plant, as about 5 ha would be needed for this purpose to achieve a peak output of 5 MWe, whereas the reservoir area is 174 ha. Thus, about 3 per cent of the reservoir area would be occupied by the floating PV. The scenarios discussed below do not explicitly describe revenues from the PV array, which will vary depending on solar irradiation and the local power market. However, as can be seen by the large increase in PV installations going on nationwide, solar installations are proving themselves to be profitable. Our focus is rather on the value that can be added by an integrated hydro/solar/battery system, focusing on the energy storage value. Two scenarios will be examined, based on seasonal flows.

3.1.1 Scenario 1: Wet season

Water sufficient to operate the powerhouse at full gate opening (allowing operation at maximum output) is available 24 hours per day, for 50 per cent of the year. In this case, ramping down the hydropower units during solar peak production could be counterproductive, as water would need to be spilled from the already full reservoir. However, it is possible that, depending on the specifics of the power purchase agreement, ramping down when there is surplus solar energy could still be cost effective. In any case, the battery component of the posited system could be used to store excess solar energy and then to provide it to the grid during peak demand, presumably at an attractive price from the standpoint of the generator.

For this example, we have assumed a 0.5 MW battery with 4 h of storage (2 MWh). If peak energy pricing averages \$100/MWh, the battery could provide a revenue stream of about \$170/day or \$62 050/year. If the battery portion of the DIGS costs about \$800 000, as shown in Table 1, this implies a payback period of about 13 years. To be conservative, in this analysis we have not considered ramping the hydropower system up and down during the wet season to store energy. For this paper, we assume that the wet season and the dry season each occur for about 50 per cent of the year, recognizing that this will vary from facility to facility, as well as over time.

As a further revenue enhancement, it should be noted that during the wet season, there may be an opportunity to use a portion of the hydropower capacity without adding to the amount of water discharged through the spillway, by charging electric vehicles (EVs) at or near the site.

3.1.2 Scenario 2: Dry season

In this case, there will be insufficient water to operate the powerhouse at full gate opening, 24 h/day, for 50 per cent of the year. It can be further assumed that the available water volume is less than or equal to the amount needed to run the powerhouse at full gate opening for 20 h/day, net of any minimum release requirements. In this case, there is an opportunity to use the reservoir to provide at least 4 h of energy storage. Assuming that 75 per cent of the hydropower capacity can be used for energy storage, this provides the potential for daily storage of $4 \times 5 \times 0.75 = 15$ MWh. If peak energy pricing averages \$100/MWh, the hydro storage could provide a revenue stream of about \$1500/day or \$273 500 per dry season, in addition to the energy storage that the battery could provide.

If the non-PV portion of the complete DIGS costs about \$1.1 million, as shown in Table 1, these figures imply about a three to four year payback period overall, taking into account both wet and dry seasons. Table 1 assumes that 75 per cent of the full hydropower capacity of the plant is available for ramping up and down; 'hydro storage revenue' would be reduced in proportion to reductions in the ramping range.

In Table 1, 'BOP' is the balance of plant equipment; 'PCS' is the power conversion system. In addition to items noted above, the DIGS approach would provide the following additional benefits:

- The ability to provide enhanced ancillary services, such as frequency control and voltage support.
- The possibility to operate the DIGS system as a resilient microgrid, which may be especially valuable in case of a major grid upset. Note that, as reported in the 19 May 2021 *Wall Street Journal*, ransomware

Table 1: Assumptions and results for 5 MW DIGS

Item	Amount
Hydro capacity (MW)	5
Battery capacity (MW)	0.5
Battery storage output (MWh)	1.7
Solar capacity (MWe)	5
Engineering	\$145 000
Floating PV including invert	\$5 000 000
Battery	\$800 000
BOP	\$86 000
PCS	\$27 500
Total Cost	\$6 058 500
Subtotal not including PV	\$1 058 500
Percentage of reservoir for solar	2.9
'Dry season' percentage of the year	50
Hydro storage revenue	\$273 750
Battery storage revenue	\$62 050
Total annual storage revenue	\$335 800

attacks resulting in denial of the electricity service represent a real threat to grid systems, which microgrids may be able to mitigate.
• An improved ability to perform black start if required.
• Reduced operating wear and tear on the hydropower units as a result of the reduced amount of governor responses to short-term fluctuations in demand.
• The ability to use the battery storage system to provide UPS (uninterruptable power supply) services to the hydropower plant.

3.2 Alder dam, Washington

Alder dam, operated by Tacoma Power, is a concrete gravity arch dam (with some embankment sections) on the Nisqually river in the state of Washington. The impounded water forms Alder Lake, extending about 11 km upstream, with a storage capacity of 0.29844 km^3. With 45 km of shoreline, the lake is a popular recreation spot close to the Mount Rainier National Park. Water from Alder Lake is conveyed to two generators at the base of the dam, each of which produces 25 MW for a total capacity of 50 MW. About 3 km downstream is LaGrande dam.

This configuration may offer particular advantages for the DIGS approach, as it is likely that releases from the Alder plant could vary over a wide range from very low flows to flows that use the full generating capacity, since the nearby LaGrande facility should be able to act as a reregulation reservoir.

There appears to be more than enough space in the reservoir to deploy floating solar PV with a capacity about equal to that of the hydropower plant, as only about 50 ha would be needed for this purpose to achieve a peak output of 50 MWe, and the reservoir area is 1240 ha. Thus, about 4 per cent of the reservoir area would be occupied by the floating PV. The scenarios discussed below do not explicitly describe revenues from the PV array, which will vary depending upon irradiation and the local power market.

3.2.1. Scenario 1: Wet season

Water sufficient to operate the powerhouse at full gate opening is available 24 h/ day, for 50 per cent of the year. Thus, ramping down the hydropower units during solar peak production could be counter-productive, as water would need to be spilled from the already full reservoir. However, it is possible that, depending on the specifics of the power purchase agreement, ramping down when there is surplus solar energy could still be cost effective. In any case, the battery component of the posited system could be used to store excess solar energy and then to provide it to the grid during peak demand, presumably at an attractive price from the standpoint of the generator. For this example, we have assumed a 5 MW battery with 4 h of storage (20 MWh). If peak energy pricing averages $100/MWh, the battery could provide a revenue stream of about $1700/day or $620 500/year. If the battery portion of the DIGS costs about $8 million, as shown in Table 2, this implies a payback period of about 13 years. To be conservative, in this analysis we have not considered ramping the hydropower system up and down during the wet season to store energy.

3.2.2 Scenario 2: Dry Season

In this scenario, there will be insufficient water to operate the powerhouse at full gate opening, 24 h/day, for 50 per cent of the year. As before, it can be assumed that the available water is less than or equal to the amount required to run the powerhouse at full gate opening for 20 h/ day, net of any minimum release requirements. In this case, there would be an opportunity to use the reservoir to provide at least 4 h of energy storage. Assuming that 0.75 per cent of the hydropower capacity could be used for energy storage, this provides the potential for daily storage of $4 \times 50 \times 0.75 = 150$ MWh. If peak energy pricing averages $100/MWh, the hydro storage could provide a revenue stream of about $15 000/day or $2.735 million per dry season, in addition to the energy storage that the battery could provide.

If the non-PV portion of the complete DIGS costs about $9.3 million, as shown in Table 1, these figures imply about a three-year payback period overall, taking into account both wet and dry seasons. Table 1 assumes that 0.75 per cent of the full hydropower capacity of the plant is available for ramping up and down; 'hydro storage revenue' would be reduced in proportion to reductions in the ramping range.

The alert reader will have noticed that our assumptions result in a linear relationship between hydropower plant size and annual storage revenue. While there are some savings on the cost side with larger projects, it should be noted that the assumptions provided are – assumptions, albeit reasonable ones. More accurate numbers can be generated with more site-specific information.

Table 2: Assumptions and results for 50 MW DIGS

Item	Amount
Hydro capacity (MW)	50
Battery capacity (MW)	5
Battery storage output (MWh)	17
Solar capacity (MWe)	50
Engineering	$179 000
Floating PV including invert	$50 000 000
Battery	$8 ,000 000
BOP	$860,000
PCS	$275,000
Total cost	$59 314 000
Subtotal not including PV	$9 314 000
Percentage of reservoir for solar	4
'Dry season' percentage of the year	50
Hydro storage revenue	$2 737 500
Battery storage revenue	$620 500
Total annual storage revenue	$3 358 000

3.3 Lower Se San 2, Cambodia

Based on information developed by the Natural Heritage Institute [NHI, 2017[4]] , the 400 MW Lower Se San 2 (LSS2) hydropower project in Cambodia is configured with eight 50 MW tubular bulb tubular generating sets with an estimated average annual output of 1912 GWh. The reservoir has a total gross storage capacity of 1792.5×10^6 m^3, of which the active storage is 333.3×10^6 m^3. Less than 2 per cent of the 33 500 ha reservoir would be needed to provide a floating solar component equal to the hydropower plant capacity of 400 MW.

For Lower Se San 2, the dry season appears to last for about 5 months (41.7 per cent of the year). There is a significant degree of variation in storage levels on a daily basis (about 1 m) which could be used to advantage for energy storage.

3.3.1 Scenario 1: Wet season

Water sufficient to operate the powerhouse at full gate is available 24 hours per day for seven months of the year. In this case, ramping down the hydropower units during solar peak production could be counter-productive, as water would need to be spilled from the already-full reservoir. However, it is possible that, depending on the specifics of the power purchase agreement, ramping down when there is surplus solar energy could still be cost effective. In any case, the battery component of the posited system could be used to store excess solar energy and then to provide it to the grid during peak demand, presumably at an attractive price from the standpoint of the generator. For this example, we have assumed a 40 MW battery with 4 h of storage (160 MWh). If peak energy pricing averages \$100/MWh, the battery could provide a revenue stream of about \$13 600/day or \$4.964 million/year. If the battery portion of the DIGS costs about \$64 million, as indicated in Table 3, this implies a payback period of about 13 years for the battery as a standalone device. To be conservative, in this analysis we have not considered ramping the hydropower system up and down during the wet season to store energy.

3.3.2 Scenario 2: Dry season

In this scenario, there is insufficient water to operate the powerhouse at full gate, 24 hours per day, for 5 months (41.7 per cent) of the year. It can be further assumed that the available water is less than or equal to the amount needed to run the powerhouse at full gate opening for 20 h/day, net of any minimum release requirements. In this case, there will be an opportunity to use the reservoir to provide at least 4 h of energy storage. Assuming that 0.75 per cent of the hydropower capacity can be used for energy storage, this provides the potential for daily storage of 4 × 400 × 0.75 = 1200 MWh. If peak energy pricing averages \$100/MWh, the hydro storage could provide a revenue stream of about \$120 000/day or \$18.25 million per dry season, in addition to the energy storage that the battery could provide.

If the non-PV portion of the complete DIGS costs about \$73.5 million, as shown in Table 1, these figures imply about a three to four-year payback period overall, taking into account both wet and dry seasons. Table 1 assumes that 0.75 per cent of the full hydropower capacity of the facility is available for ramping up and down; 'hydro storage revenue' would be reduced in proportion to reductions in ramping range.

Table 3: Assumptions and results for 400 MW DIGS

Item	Amount
Hydro capacity (MW)	400
Battery capacity (MW)	40
Battery storage output (MWh)	136
Solar capacity (MWe)	400
Engineering	\$419 000
Floating PV including invert	\$400 000 000
Battery	\$64 000 000
BOP	\$6 880 000
PCS	\$2 200 000
Total cost	\$473 499 000
Subtotal not including PV	\$73 499 000
Percentage of reservoir for solar	1.2
'Dry season' percentage of the year	41.7
Hydro storage revenue	\$18 250 000
Battery storage revenue	\$4 964 000
Total annual storage revenue	\$23 214 000

4. Applicability

Not all existing hydropower facilities are appropriate for the DIGS approach. It is desirable, for example, that in addition to having operational flexibility to ramp hydro output up and down at least on a daily basis, the dam should be able to handle fluctuating reservoir levels without damage. In some cases, this may favour a concrete rather than an embankment dam.

Turbine, generator, gateworks and equipment should be able to be ramped up and down without impacting their longevity, or unduly increasing their maintenance requirements.

Variability of releases from a hydropower plant must stay within appropriate limits which can be established in permits. In some cases, this may involve installing a reregulating dam downstream of the hydropower plant. In many cases, the degree and rate of hydropower ramping up and down will be constrained by environmental or other considerations, which are important and must be addressed on a site-specific basis.

5. Revenue enhancement

The value of such hybrid hydro/solar/battery combinations can potentially be enhanced by using a modern real-time energy marketing system, such as the Fluence AI-powered Trading Platform, which was selected to provide market bidding services for Pacific Gas and Electric Company's 182.5 MW, 730 MWh battery energy storage system at Moss Landing, California. As announced by Fluence, the Trading Platform uses artificial intelligence, advanced price forecasting, portfolio optimization and market bidding algorithms, intended to ensure the system is responding optimally to market and reliability needs in the California Independent System Operator (CAISO) wholesale market. Fluence's 17 February 2021 statement indicates that, by providing asset and portfolio managers with updated price forecasts and optimized bids every hour, PG&E will maximize the value of the asset for PG&E customers, improve grid reliability and efficiency, and support California's transition to a more sustainable and resilient grid.

In this case, one can make the simple assumption that the wholesale market value of stored energy is \$100/MWh.

6. Hydropower equipment condition assessment

To achieve the goals of implementing a 'hydro + solar + battery' approach at an existing hydropower plant, it is crucial that a condition assessment of the hydro plant be carried out, to confirm the suitability of operating in the new (hydro + solar + battery) scheme.

Furthermore, the condition evaluation of an existing hydropower unit regarding suitability of the hybrid (hydro + solar + battery) approach will need to have additional checks which go beyond a conventional hydropower condition evaluation.This evaluation needs to confirm both the health of the plant, as well as compatibility of design with the proposed DIGS operating regime.

Once the evaluation has been done, it can be determined whether there is a need to refurbish or upgrade any of the hydro components, to that they will perform reliably in the DIGS regime; or, possibly the proposed DIGS regime could be modified to match the capabilities of the existing hydro equipment.

A large portion of hydropower units in operation are custom-built facilities, which have seldom been mass produced. This makes it particularly important that the condition assessment be carried out by a knowledgeable party, with specialized hydropower expertise and experience.

Table 4: DIGS/ HydroBattery possible deployment by State (2019 hydro capacity data)

State	Capacity (MW)	Facilities	MW storage @ 25%	MWh @ 4 h storage	Value, $\$10^6$ @ \$100/kWh
Alabama	3318	23	830	3320	332
Alaska	476	32	119	476	48
Arizona	2718	10	680	2720	272
Arkansas	1321	19	330	1320	132
California	10 074	251	2519	10 076	1008
Colorado	668	46	167	668	67
Connecticut	116	13	29	116	12
Florida	44	1	11	44	4
Georgia	1963	30	491	1964	196
Hawaii	34	8	8	32	3
Idaho	2687	74	672	2688	269
Illinois	40	9	10	40	4
Indiana	96	5	24	96	10
Iowa	129	3	32	128	13
Kentucky	1097	10	274	1096	110
Louisiana	192	1	48	192	19
Maine	714	54	178	712	71
Maryland	551	2	138	552	55
Massachusetts	271	30	68	272	27
Michigan	362	55	90	360	36
Minnesota	215	27	54	216	22
Missouri	506	6	127	508	51
Montana	2701	23	675	2700	270
Nebraska	330	10	82	328	333
Nevada	1052	6	263	1052	105
New Hampshire	514	33	128	512	51
New Mexico	82	5	20	80	8
New York	4692	164	1173	4692	469
North Carolina	1890	41	473	1892	189
North Dakota	583	1	146	584	58
Ohio	129	5	32	128	13
Oklahoma	819	10	205	820	82
Oregon	8429	65	2107	8428	843
Pennsylvania	920	17	230	920	92
South Carolina	1365	31	341	1364	136
South Dakota	1648	4	412	1648	165
Tennessee	2504	28	626	2504	250
Texas	708	24	177	708	71
Utah	265	29	66	264	26
Vermont	328	47	82	328	33
Virginia	822	25	206	824	82
Washington	21 177	76	5294	21 176	2118
West Virginia	371	12	93	372	37
Wisconsin	538	66	134	536	54
Wyoming	303	16	76	304	30

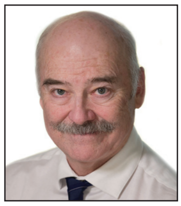
7. Potential for the future

The DIGS/HydroBattery approach may prove to be a key element in an all-renewable energy future in North America and elsewhere. Based on US Energy Information Agency data [EIA, 2020[4]] and assuming that about 25 per cent of existing conventional hydro capacity can be made suitable for use as a DIGS/HydroBattery, almost all US states have significant conventional hydropower assets that could be deployed in this way, as shown in Table 4. This Table conservatively assumes the HydroBattery energy storage value at $100/kWh of storage capacity, based on the fact that grid-scale battery storage costs of the order of $400/kWh (Capex), and is increasing rapidly. This value, based on about 80 GWh of storage as listed above and totalling about $8 billion, awaits development. About half of the total is located in the three West Coast states (California, Oregon and Washington).

As we transition to a new energy future, the USA is striving to achieve 100 per cent renewable electricity and the DIGS and HydroBattery concept could be one of the keys to that achievement. ◊

References

1. **Donalek, P.,** ***et al.***, "Hybrid Solar/Hydropower for Mitigation of Drought Impacts on Power Generation", HydroVision, USA; 2018.
2. **USR and IWRMP**, "Climate Change", Chapter 9, (Draft); 2018.
3. **NHI**, "Sambor Hydropower Dam Alternatives Assessment", Natural Heritage Institute, USA; December 2017
4. **IEA**,"Annual electricity data: Existing capacity", International Energy Agency, www.iea.gov; 2020.



Mark Allen, Vice President of Stantec in Chicago, USA, manages domestic and international projects, specializing in renewable energy, including hydroelectric development. His experience includes two large hybrid hydro/solar/battery projects in Central Africa; two of the largest hydropower developments in the world (Jinping 1 and Xi Luo Du in China); two small hydro developments in Jamaica (Rio Bueno and Maggotty Falls Expansion); the New Bong Escape hydro development and the 102 MW Gulpur hydro project in Pakistan, the Dasu Ecological Studies project in Pakistan; and, a 156 MW privately developed hydropower project planned for Guyana. In addition, he provides technical services related to solar power and to energy efficiency projects, including studies for wastewater treatment plants, and a pumping efficiency study for water treatment plants

Stantec, 224 S Michigan Ave, 1400 Chicago, IL 60604, USA.