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Implementation of Voltage and Frequency Ride-Through Requirements in Distributed Energy Resources Interconnection Standards

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Implementation of Voltage and Frequency Ride-Through Requirements in Distributed Energy Resources Interconnection Standards

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Abstract

The rapid deployment of distributed resources (DR), principally photovoltaic systems, is driving changes in distribution system interconnection standards. While much of the effort is on mitigating local issues such as voltage control and protection coordination, there is also an increasingly urgent need to consider the effect that DR have on bulk power system reliability. A major concern is that large-scale deployment of DR without adequate voltage and frequency tolerance will negatively affect bulk system reliability and performance by making disturbance recovery more difficult. This report describes the technical implications of incorporating minimum voltage and frequency disturbance ride-through standards as part of the context of DR interconnection standards (IEEE Standard 1547). We discuss approaches to incorporate voltage and frequency tolerance, while preserving the effectiveness of existing DR interconnection.

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1 Background

It is becoming increasingly evident that large-scale penetration of distributed resources (DR) that have sensitive voltage and frequency trip points with short delay times, as mandated by the current version of IEEE Standard 1547, pose a risk to bulk power system security. This issue is well described in the NERC Integration of Variable Generation Task Force Task 1-7 report.[1] This NERC report recommends that IEEE 1547 be modified to incorporate voltage and frequency ride-through requirements (VRT and FRT, or collectively V/FRT). IEEE Standard 1547 is presently being amended to provide more flexibility in the "must trip" requirements, which allow V/FRT to be implemented by utilities or other local entities, but do not mandate these ride-through capabilities. The base IEEE 1547 standard, however, is required by recently-changed IEEE Standards Association rules to undergo full review and potential revision. This is in contrast with the prior expiration of the IEEE Standard 1547 in 2008 when the sponsor (IEEE Standards Coordinating Committee 21) submitted the unmodified original standard for reaffirmation ballot. With the changed IEEE-SA rules, reaffirmations are no longer allowed and thus a working group has been convened to review and potentially revise the IEEE 1547. This provides an opportunity to introduce for consideration the possible addition of V/FRT requirements.

In addition to helping preserve bulk power system reliability, incorporating minimum default V/FRT requirements in IEEE Standard 1547 would reduce complexity of equipment design and certification. It is recognized that there are technical challenges involved and compromises necessary to implement voltage and frequency ride through for DR. The potential for increased DR unit cost and interconnection costs, tradeoffs between potential reduction in distribution system performance versus the requirement for more complicated distribution protection schemes in order to accommodate DR with V/FRT capabilities, as well as questions of jurisdiction are factors which drive opposition to the imposition of V/FRT requirements on DR. This white paper describes these issues that complicate the acceptance of these requirements. These issues can be categorized as DR technical limitations, difficulties in meeting other distribution system compatibility requirements, and political issues.

2 Ride-Through Requirement Goals

The underlying goal for DR ride-through capability is avoidance of significant bulk system security deterioration as a result of DR tripping during critical grid events that result in voltage or frequency deviations. It is not reasonable to require DR to ride through all possible grid events, but rather ride-through requirements for DR should be designed to be generally consistent with the severity of events for which the bulk system is designed. By limiting DR ride-through requirements to realistic bulk grid needs, equipment limitations and conflicts with other DR integration requirements can be greatly alleviated.

2.1 Voltage Ride-Through

Bulk transmission system faults result in voltage depression over an extended area, both during the duration of the fault, as well as during post-fault dynamic behavior. In the post-fault period, high voltages

[1] NERC Integration of Variable Generation Task Force (IVFTF1-7) Report, "Performance of Distributed Energy Resources During and After System Disturbance Voltage and Frequency Ride-Through Requirements ", December 2013.

may also occur over a wide area due to dynamic “backswing”. These voltage deviations at the bulk transmission level tend to propagate over a wide area to the distribution systems to which DR are connected. Without VRT requirements, and particularly with the present IEEE 1547 “must trip” requirements for voltage deviations, a potentially large amount of DR generation capacity could be tripped simultaneously as a result of a bulk grid event that stresses the grid. This has the potential for aggravating the bulk grid disturbance, and violates a fundamental principle of bulk system planning – generation should not be lost as a result of a grid fault that is within the planning criteria.

Bulk grid planning studies, including large generation interconnection studies, are based on locationally-specific contingencies selected according to established criteria. It is impractical to perform specific transmission studies for DR interconnection, and thus it is necessary to define uniform DR VRT performance requirements in terms of generic voltage and frequency versus time criteria that reflect the voltage and frequency conditions which might be typically observed at the DR points of interconnection during critical bulk grid events that are within reliability planning criteria.

Voltages on distribution systems fed radially from transmission buses, subjected to three-phase faults, may be near zero for the duration of the fault. However, the amount of DR capacity so affected is unlikely to be significant to the security of the bulk grid. Considering the balance between the major challenges for some DR technologies to achieve extremely low voltage ride-through performance, and the minimal impacts on bulk grid security from the potential loss of a very small amount of DR capacity likely to experience such low voltage, it is unnecessary and unduly onerous to mandate extreme LVRT performance (i.e., so-called ZVRT, or zero-voltage ride-through).

As distance from a transmission fault location increases, the distribution system voltage depression is progressively less severe, but the amount of potentially affected DR capacity increases. The lowest portion (fault portion) of LVRT requirement profiles should be based on a reasonable expectation that loss of DR experiencing more severe voltage depression would not be of significance to the bulk grid. Present NERC registration criteria do not consider single generation units less than 20 MW, or generating facilities with an aggregate capacity less than 75 MW, to be bulk generation assets. Therefore, a reasonable criterion is that a potential loss of less than 20 to 75 MW of DR capacity is below the threshold of bulk-grid significance. LVRT requirements can be defined such that for a typical DR capacity density, and a typical fault-voltage versus radius gradient, the amount of potential DR loss is below this threshold. However, both potential DR capacity density and fault voltage gradients are locationally-dependent. For more densely-loaded portions of the grid, the potential DR capacity density also would tend to be greater. However, the more densely-networked transmission system needed to support such a densely-loaded area would also tend to have a more limited geographic extent of voltage depression during a fault. Hence, these two factors tend to track each other, making generalizations about LVRT levels and potential lost generation more widely applicable.

In addition to the severity of voltage deviation, VRT duration requirements should be coordinated with bulk grid reliability criteria. The duration of the initial lowest-voltage portion of a LVRT performance requirement should be comparable to the fault durations for which the bulk transmission system is designed. Maximum clearing times for bulk-grid single-phase fault events are often longer than for three-phase faults. At the distribution level, however, the voltage depression severity due to transmission single-phase faults is mitigated to a substantial degree by the delta-wye transformer connections between the transmission and distribution systems. Thus, the lowest-voltage portion of a LVRT curve should have a duration consistent with bulk grid three-phase fault clearing times, and only a less-severe LVRT performance should be required for single-phase fault clearing times. If a portion of the LVRT performance requirement is intended to cover post-fault dynamic voltage recovery, this portion of the curve should be based on realistic voltage-recovery profiles of well-designed transmission systems, rather than worst-case scenarios of very marginal voltage recovery for bulk systems that are on the threshold of voltage instability. Bulk systems having such poor voltage recovery need to be corrected (e.g., with reinforcements, revised operating restrictions, FACTS devices, etc.), and DR should not be called upon to make that correction.

Faults on local transmission or subtransmission systems can cause very low distribution voltages for longer periods than bulk transmission faults. These subtransmission faults, however, are not critical to the bulk grid, and these faults should not be the basis for VRT performance requirements. The primary purpose of VRT requirements is preservation of bulk grid security by avoiding aggravation of bulk system disturbances.

2.2 Frequency Ride Through

Frequency is effectively uniform across an entire interconnection, or portion of an interconnection in the case of a grid breakup following an exceptionally severe contingency. (There can be low-magnitude, short-duration frequency variations at specific locations due to dynamic angular swings; these variations are of insufficient magnitude to be of relevance to this discussion.) The frequency of the interconnection is determined by the instantaneous balance of load and generation, and any disturbance causing loss of load, transmission or generation can perturbate the grid frequency. An underfrequency caused by loss of generation can be aggravated by further loss of generation in response to the underfrequency—for bulk power system reliability this is referred to as "cascading". Therefore, reliability rules require utilities to implement automatic load-shedding schemes that respond to underfrequency events, and bulk generators are required to have under-frequency ride-through capability that extends beyond these load shedding frequency duration curves. Loss of generation due to an overfrequency would appear to be in the direction to correct the generation-load mismatch, but excessive loss of generation can rapidly turn an overfrequency event into an underfreqeuncy event due to overcorrection. Thus, bulk generators are also required to have defined high-frequency ride-through capability.

By virtue of connection to the grid, DR is part of the overall generation-load balance. With increasing DR penetration, it is increasingly important for DR to have FRT capabilities equivalent of that required of bulk generation. *It should be emphasized that local penetration (e.g., feeder level or distribution substation level penetration) is irrelevant to this discussion. It is the penetration and off-frequency behavior of all DR in the interconnection that is relevant—and thus an issue for the reliability of the bulk power system.*

2.3 DR Size

The potential impacts of DR tripping on the bulk grid are a function of the aggregate DR capacity lost, and it makes no difference if the loss of 100,000 10kW DR units, or 100 10MW units. The net effect is the same as if one 1,000 MW bulk generation plant is lost, a level of substantial significance to the bulk grid. Therefore, V/FRT requirements need to be applied to DR of all sizes, and irrespective of whether the units are single-phase or three-phase.

3 Technical Limitations of Various DR

V/FRT requirements, particularly LVRT requirements, can be challenging to achieve for certain types of DR due to physical limitations of the generating equipment. The degree of difficulty, of course, depends on the severity of the requirements.

3.1 Voltage Ride-Through

A clear example of an inherent technical limitation to LVRT performance is the issue of synchronous generator DR loss of synchronism (transient instability) as a result of very low voltage persisting beyond a certain duration. Bulk generators also have this limitation. DR synchronous generators and prime movers, however, tend to have lower per-unit inertias than large generators, making it sometimes difficult for the DR to remain stable for a transmission fault case where nearby large generators are capable of maintaining stability. This is particularly the case for engine driven generators, which comprise the large majority of synchronous generator DR. Inertia can be increased with flywheels. Stability may also be improved by fast throttling of the prime movers, which tend to be much more responsive than large gas, steam, and hydro turbines. Each of these measures increases the cost of these generators, and thus vendors and other proponents of this type of generation tend to oppose V/FRT imposition.

Some forms of electromechanical generators are interfaced to the grid using inverters, including PV, Type 3 (doubly-fed) and Type 4 (full conversion) wind turbines, and microturbines. Although these machines do not have the normal transient stability constraints, a long-duration of low voltage can inhibit transmission of real power from the machine, potentially causing an overspeed situation. Again, the relative difficulty of meeting low voltage ride-through (LVRT) requirements is a function of the severity of the requirements. Reasonable requirements that are coordinated with scenarios within bulk electric system (BES)[2] planning criteria are not likely to cause such issues. Some LVRT requirements imposed elsewhere in the world are so arbitrarily severe that there have been challenges for some equipment to meet the requirements due to overspeed.

Low voltage can also cause loss of auxiliaries in some types of generators used in DR applications, complicating LVRT requirements. An example is wind turbines, where auxiliary power is used to operate blade pitch and nacelle yaw motors. Most types of DR require auxiliary power to energize their controls, and larger inverters require fans and pumps for cooling. Wind turbine designs have evolved to include backup stored energy for auxiliaries, as have other inverters designed to meet transmission grid codes. Imposition of unduly onerous LVRT requirements on DR could exceed the capabilities of current designs,

[2] BES is defined in the NERC Glossary of Terms (http://www.nerc.com/files/Glossary_of_Terms.pdf) While NERC maintains and sets North American-wide planning standards, many regional and/or system specific planning criteria are also set by states, ISO/RTOs, and/or Regional Entities.

increasing equipment costs. If the requirements on DR are coordinated with those in wide acceptance for transmission-connected equipment, most DR would be compliant.

While low voltage is most directly associated with major events threatening bulk power system security (operating reliability and grid stability), high voltages may also occur during disturbances. Therefore, many transmission grid codes have imposed high-voltage ride-through (HVRT) requirements. High voltages have direct impact on equipment of all types, particularly power electronics. Surge arresters and varistors used to protect equipment are also quite sensitive to the magnitude and duration of temporary overvoltages. It is important that HVRT requirements be reasonable, and not in excess of magnitudes that the distribution equipment can withstand. High voltages involved in critical bulk system dynamic events tend to be during the "backswing" following fault recovery. Some proposed grid codes have specified HVRT where the time is the period since the beginning of the initiating event. For example, if an overvoltage to 1.2 p.u. might occur at one second following the initiation of a fault, and has duration at this magnitude of 0.2 seconds, these grid codes have mandated a 1.2 p.u. ride through for 1.2 seconds. This type of "envelope" specification is unnecessarily severe as the equipment is only subjected to the high voltage for 0.2 seconds. Specifications based on duration at magnitude are much more relevant to the actual grid needs, particularly for high-voltage capabilities. Reasonable HVRT requirements should not pose difficulty for well-designed DR to physically endure, but arbitrary and poorly designed requirements can drive equipment costs and thus opposition to V/FRT requirement imposition.

3.2 Frequency Ride Through

The prime movers directly coupled to synchronous generators experience speed variations as the grid frequency varies. These speed variations, and rate of speed change, can pose mechanical and combustion problems for prime movers. Speed variations can cause excitation of mechanical oscillations modes, and acceleration can cause blowout of gas turbine flames. These problems are usually associated with much larger turbine generators than used as DR. Excessively stringent FRT requirements, however, could potentially pose problems even for smaller gas turbines that might be connected to distribution systems. Again, it is important that V/FRT requirements for DR should not be made more severe than comparable BES requirements.[3]

3.3 Uniform Versus Technology-Specific Standards

There is a tendency for standards drafters to base V/FRT requirements on performance that can be readily achieved by certain types of DR, rather than to base requirements strictly on ***minimum*** system security needs as discussed previously in this document. Different types of DR vary in their inherent capabilities for withstanding voltage and frequency deviations, however. Because it is not always practically feasible to design certain types of DR technologies to meet the same performance as other types, technology-specific V/FRT requirements have been suggested. The technology-specific approach has been used in Germany where separate F/VRT requirements apply to synchronous generator DR and inverter DR.

[3] See NERC Reliability Standards: http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx. NERC's TPL family of standards are examples of NERC Reliability Standards that cover transmission planning requirements.

From a philosophical standpoint, V/FRT requirements should be based on actual bulk power system needs, and these needs are inherently invariant with the type of generation to be interconnected. In most cases, ride-through requirements that are based on the true functional needs of bulk grid security and are effectively comparable to requirements met by bulk generation assets, should not be onerous for DR of all types to achieve. Another advantage to technology-neutral V/FRT requirements is in administration, particularly when the categorization of certain technologies is not as easily defined. For example, a doubly-fed wind turbine generator is a rotating machine that has many characteristics of an inverter-interfaced device. Technology-specific requirements can be ambiguous to apply when technologies do not fit well into predefined categories.

A counterargument to the technology-neutral approach, however, is that each type of generation has its own virtues and limitations, and that the grid is better off if standards extract the greatest achievable performance from each type. For example, although synchronous generation DR has more difficulty with long, severe LVRT requirements, it inherently has better system strengthening and voltage support capabilities than an inverter. An inverter is much more easily designed to comply with severe LVRT, but its inherent current limitations limit voltage support capability.

4 Distribution Compatibility

There are a number of requirements placed on DR, for purposes of compatibility with the distribution systems to which they are connected, that are more difficult to achieve simultaneously with V/FRT capabilities. These requirements are embodied in the present IEEE Standard 1547, and are

- Detection of faults
- Avoidance of protracted islanding
- Coordination with reclosing

4.1 Fault Detection

IEEE 1547 states “The DR unit shall cease to energize the Area EPS for faults on the Area EPS circuit to which it is connected.” DR, even synchronous generator DR, have very limited fault current contribution relative to the fault current supplied by the grid. In the case of inverters, the fault current contribution is effectively nil. As a practical matter, a DR is often unlikely to be able to detect a fault on a feeder by overcurrent or distance relaying while the feeder remains energized by the substation. After the substation breaker (or line recloser, or lateral fuse) trips or clears, the DR is more likely to detect the fault using overcurrent or distance relaying if it has sufficient fault current contribution. This is called “sequential tripping” and is commonly accepted to be compliant with IEEE 1547. In the case of inverters, current is not usually a satisfactory means of detecting a fault. These DR typically base fault detection on an undervoltage basis. This often will detect the fault even with the substation source still driving the fault current, but may not detect until the feeder is deenergized in some cases.

Undervoltage detection of faults is inherently a very non-selective protection approach. To the DR, an undervoltage caused by a fault on the feeder to which it is connected is often indistinguishable from a fault on the transmission system. Imposition of LVRT requirements inherently places a minimum time on the detection of faults by undervoltage means.

The requirement for DR to detect faults is primarily intended to keep DR from causing a protracted contribution of current to grid faults, thus increasing the damage those fault can cause, as well as possible false operation of fuses or other switchgear. The types of DR dependent on undervoltage detection of faults inherently have very little current contribution. Thus accommodating LVRT requirements is possible if the "detect all faults" requirement is not over-interpreted to require fast tripping of DR that does not have a significant contribution to fault current magnitude, and is unlikely to cause fuse or relay misoperations. Appropriate modification to the requirements of the new IEEE 1547 can be made to resolve this conflict.

4.2 Avoidance of Islanding

IEEE 1547 requires that the DR "shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island." The standard does not impose any particular approach to meeting this requirement, but does offer examples of satisfactory approaches in an informative (i.e., not normative) footnote:

1. "The DR aggregate capacity is less than one-third of the minimum load of the Local EPS.
2. The DR is certified to pass an applicable non-islanding test.
3. The DR installation contains reverse or minimum power flow protection, sensed between the Point of DR Connection and the PCC, which will disconnect or isolate the DR if power flow from the Area EPS to the Local EPS reverses or falls below a set threshold.
4. The DR contains other non-islanding means, such as a) forced frequency or voltage shifting, b) transfer trip, or c) governor and excitation controls that maintain constant power and constant power factor."

All of the above rely on a change in the island's frequency or voltage to detect the island (with a few exceptions). In the first and third examples, the island voltage or frequency is expected to collapse due to insufficient DR capacity to sustain the island. In the second example, an active anti-islanding scheme is depended upon. This is the approach embodied within UL1741. Most of these schemes are designed to force the island's voltage or frequency to the trip points. (Some schemes rely on detecting the driving point impedance through signal injection or changes in harmonic distortion; thus the exceptions cited above.) The fourth example relies on the natural imbalance between generation and load of real and reactive power to eventually drive voltage or frequency to the trip points.

Widening the voltage and frequency trip points in order to accommodate V/FRT inherently increases the time to detect an island, and increases the real and reactive power mismatch range, or "non-detection zone" where island detection may not occur at all for some schemes. The need to avoid protracted unintended islanding is nearly universally accepted within the DR and utility distribution communities alike. While the two second limit is somewhat arbitrary, it does provide coordination with some reclosing schemes (discussed later) and sets a defined limit so that islands of indefinite duration do not occur.

It should be noted that the entire interconnected grid is itself an island. Accommodating V/FRT while still meeting the anti-islanding requirements requires that the DR detect and identify the difference between voltage and frequency deviations caused by a disturbance on the bulk system and disturbances on the very small island on which it might be isolated in an inadvertent island. The competing requirements pose an inevitable conflict which will require either improvements to the voltage and frequency deviation based anti-islanding schemes now in wide use, or substitution of other schemes not dependent on these deviations. Examples of the latter include impedance detection schemes, “tracer” or PLC signal schemes where a carrier signal is injected at the substation and the absence of which indicates a DR-supported island, and communicated message schemes such as direct transfer trip. None of these alternative solutions are a panacea; each has its own pitfalls and complications, both technical and cost. Some of the passive anti-islanding approaches suggested in the footnote in IEEE 1547 may not be valid, or have reduced validity, with V/FRT implemented.

There is an apparent need for research into improved means to avoid unintended DR-supported islands, including:

- More effective autonomous active anti-islanding schemes,
- Potential for mutual interference between different anti-islanding schemes and types of DR.
- Validation of passive schemes and generation versus load rules-of-thumb for the wider voltage and frequency trip points needed for V/FRT.
- Development of lower-cost approaches to non-autonomous anti-islanding schemes, including tracer signal and communicated approaches.

Unless it can be demonstrated to stakeholders that V/FRT can be implemented without compromise of unintended islanding limits or significant increase in DR equipment or DR interconnection costs, opposition to V/FRT can be expected to continue and be strident.

4.3 Coordination with Reclosing

It is widely understood that reclosing into an island poses a risk of an out-of-phase reclose that can be potentially destructive to synchronous generator DR connected to the island. Less well recognized is that such an out-of-phase reclosing also poses a risk of transient overvoltages that may be damaging to utility and customer equipment, cause severe transformer and motor inrush currents that may cause undesired relay pickup or fuse operation, and torque transients potentially injurious to customer motors and mechanical drivetrains. The frequent statement that out-of-phase reclose is not a problem with inverter DR because the inverters are self-protected, is inaccurate. IEEE Standard 1547 makes the vague statement that “The DR shall cease to energize the Area EPS circuit to which it is connected prior to reclosure by the Area EPS.” Many interpret this clause to impose an additional requirement on island detection. If the feeder reclosing time is less than two seconds, then the allowable island “cease to energize” time for any DR on the feeder is that reclosing time. In other words, the effective island detection time is the lesser of two seconds or the specific feeder reclose time. Others, however, interpret this same clause to require that the utility adopt whatever means necessary to accommodate DR that needs two seconds to detect islands. Such accommodation can be made by increasing the minimum reclose delay beyond two seconds, or by using an undervoltage-permissive scheme to block reclosing as long as an island is energized.

Implementing V/FRT, and the resulting impact on island detection, will increase utility concerns about reclosing coordination. Utilities may perceive an increased need to extend reclose delays, with consequent negative impact on power quality, or implementation of undervoltage-permissive reclose schemes with consequent cost impacts. It should be noted that many electro-hydraulic feeder reclosers now in use are not compatible with implementation of an undervoltage-permissive scheme, and these reclosers would need to be replaced. All of these concerns are a likely driver for opposition to V/FRT requirement imposition.

5 Other Issues

The Federal Energy Regulatory Commission maintains jurisdiction over the transmission and bulk generation systems. Historically, distribution systems have been deemed to subject to state regulatory jurisdiction and thus outside of the FERC jurisdiction. FERC's involvement in distributed generation in regard to the implementation of the Small Generation Interconnection Process raised a degree of controversy. The SGIP became binding only where a DR was intended to engage in interstate commerce, defined as sale of power that requires transmission over the bulk power system.

Because the need for V/FRT is being championed by NERC, the reliability organization franchised by FERC and the Canadian Provinces, concerns over jurisdiction are likely to arise. Clearly, there is a need shift the focus toward finding solutions to the technical issue that lies before us. It should always be recognized that the electric grid is an interconnected system, and that the "electrons know no jurisdiction."

The rapid expansion of generation on the distribution system affects the reliability of the bulk system in a way that has no precedent. In the past, due to low penetration levels, the manner in which assets were interconnected at the distribution level did not materially affect the bulk system. For this reason, bulk system reliability entities have not needed to be concerned about distribution-connected generation. It must be emphasized that the reliability and security of the bulk power system are important to all stakeholders.

6 Conclusions

Requirements for V/FRT should be based on rational needs for bulk power system security (operating reliability and grid stability), and should be coordinated with planning requirements applicable to BES generation assets. If the requirements are not unnecessarily onerous, it is likely that most DR technologies can comply without violating their own physical limitations. Conflicts between V/FRT and distribution compatibility requirements can be a significant challenge to overcome. While fault detection concerns can be mitigated with appropriate adjustments of the IEEE 1547 requirements, the ride-through requirements can conflict with common measures used to detect and eliminate unintended islands. Further research is needed in this area to develop readily applicable and cost-effective means to avoid a protracted island while providing V/FRT functionality needed to ensure bulk power system security with the increasing penetration of DR. Jurisdictional concerns need to be overcome with outreach to the widest possible range of stakeholders, with the goal of addressing the potential impacts to bulk system security created by the lack of minimum V/FRT requirement in the existing standards.

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